State of California • Natural Resources Agency
Department of Conservation
Director's Office
801 K Street • MS 24-01
Sacramento, CA 95814
(916) 322-1080 • FAX (916) 445-0732

Edmund G. Brown Jr., *Governor*
David Bunn, *Director*

October 8, 2015

The Honorable Mark Leno
Chair, Committee on Budget & Fiscal Review
California State Senate
State Capitol, Room 5019
Sacramento, CA 95814

The Honorable Shirley N. Weber
Chair, Committee on Budget
California State Assembly
State Capitol, Room 6026
Sacramento, CA 95814

The Honorable Fran Pavley
Chair, Committee on Natural Resources & Water
California State Senate
State Capitol, Room 5046
Sacramento, CA 95814

The Honorable Das Williams
Chair, Committee on Natural Resources
California State Assembly
1020 N Street, Room 164
Sacramento, CA 95814

The Honorable Bob Wieckowski
Chair, Committee on Environmental Quality
California State Senate
State Capitol, Room 2205
Sacramento, CA 95814

The Honorable Luis Alejo
Chair, Committee on Environmental
Safety & Toxic Materials
California State Assembly
1020 N Street, Room 171
Sacramento, CA 95814

The Honorable Ricardo Lara
Chair, Committee on Appropriations
California State Senate
State Capitol, Room 2206
Sacramento, CA 95814

The Honorable Jimmy Gomez
Chair, Committee on Appropriations
California State Assembly
State Capitol, Room 2114
Sacramento, CA 95814

DEPARTMENT OF CONSERVATION, DIVISION OF OIL, GAS, AND GEOTHERMAL RESOURCES REPORT TO THE LEGISLATURE ON THE UNDERGROUND INJECTION CONTROL PROGRAM PURSUANT TO SB 855, 2011 THROUGH 2014

Dear Senators and Assembly Members:

Senate Bill 855 (Chapter 718, Statutes of 2010) directed the Department of Conservation's Division of Oil, Gas, and Geothermal Resources (Division) to give the Legislature an annual report each January until 2015 on various features of the Division's Class II Underground Injection Control (UIC) Program. The Division last submitted required information in 2011, and now submits its 2015 report.

This report will include past due data broken out in annual figures on permits, violations, enforcement, staffing and vacancies, and new legislation and rulemaking, as required by SB 855. It also includes a quite thorough assessment of the state's UIC program in one of the two busiest regulatory regions: District 1 in Cypress, which is responsible for the regulation of some of the state's most productive fields in the Los Angeles Basin.

Though not called for under SB 855, this report also includes a summary of work to date by the Division, United States Environmental Protection Agency (U.S. EPA), and State Water Resources Control Board surrounding these issues, with copies of key correspondence memorializing the work of these three agencies. As you are aware, since mid-2014, the three agencies have been collaborating to improve the state's regulation of Class II injection in general under the Safe Drinking Water Act and, in particular, to remedy the Division's permitting of a number of injection wells in some aquifers that are not currently exempted from the Safe Drinking Water Act, but in most cases have characteristics that would make them eligible for exemption.

Finally, the report concludes with a summary, in table form, of the significant Division problems identified throughout this report, and corresponding steps being taken to address them. During the past year, State Oil and Gas Supervisor Steven Bohlen, working with his senior staff, has conducted a root-cause analysis of many of the systemic problems that have caused the Division's regulatory performance to be suboptimal. Dr. Bohlen has discussed many of these issues with you in numerous meetings and hearings conducted earlier this year. At a high level, these problems include: insufficient staffing to address increasing regulatory workload in addition to significant remedial programmatic work, poor recordkeeping on mostly paper forms and the lack of modern data tools and systems, outdated regulations that in some cases do not address the modern oil and gas extraction environment, inconsistent and undersized program leadership, insufficient breadth and depth of technical talent, insufficient coordination among field districts and Sacramento, and lack of consistent, regular, high quality technical training.

The Supervisor and his staff have enacted strategies and activities to address these long-term systemic problems as laid out in the renewal plan being released by the Department today. The Division will soon be reorganized to improve cooperation and consistency among the districts and Sacramento and to improve technical and programmatic leadership with attention focused on specific regulatory programs, heretofore never done. Teams will be organized under the following programs: UIC; Well Stimulation; Idle and Abandoned Wells and Facilities; Emerging Technologies and Regulations; Well and Data Management; Environmental Review; and Technical Training. Regular training programs are being launched. A robust rulemaking effort is under way that will update the Division's regulations to address current oil-field realities. With the passage of the 2015-2016 budget, the Division has sufficient resources needed to bring a well data management system and modern tools to the Division. Furthermore, the Division is undertaking high-visibility recruiting efforts to hire additional talented technical staff to improve all of the Division's programs, including geographical information systems and data management capabilities, monitoring and compliance of Division activities, environmental review, improvement of the UIC program, and carrying out the compliance schedule agreed to with the U.S. EPA.

As always, we are available to discuss the enclosed report and its attachments as well as the aggressive activities now under way to greatly improve the Division's regulatory performance.

Sincerely,

David Bunn
Director

Enclosures

Underground Injection Control Program Report on Permitting and Program Assessment

Reporting Period of Calendar Years 2011-2014

Prepared pursuant to Senate Bill 855 (Ch. 715, Stats. of 2010)

Prepared
By
Department of Conservation
Division of Oil, Gas, and Geothermal Resources

October 2015

SUMMARY

Section 35 of Senate Bill 855 (Chapter 718, Statutes of 2010), requires the Department of Conservation's (Department) Division of Oil, Gas, and Geothermal Resources (Division) to report annually on the following seven areas of the Division's Underground Injection Control (UIC) Program:

1) The number of underground injection permits issued by the Department
2) The average length of time to obtain a permit from date of application to the date of issuance
3) The number and description of permit violations identified
4) The number of enforcement actions taken
5) The number of staff and vacancies in the program
6) Any state or federal legislation, administrative, or rulemaking changes to the program
7) The program's assessment findings

With respect to item 7, SB 855 called for a "...report on the Underground Injection Control Program's action plan developed to address the program's assessment findings and its existing efforts to implement the plan..." This information was to be provided annually by January 30 of each year from 2011 until 2015 and cover the prior calendar year's activities. Though the first year report was submitted on February 18, 2011, subsequent reports were not undertaken. Now, with this report, we offer a detailed program assessment (item (7)) focused upon issues with the program in District 1 (the Los Angeles Basin area), one of the Division's busiest regulatory regions.

This report also summarizes progress made by the Division, the State Water Resources Control Board, and the United States Environmental Protection Agency (U.S. EPA). The three agencies have been working together since mid-2014 to systematically address a number of important deficiencies in the UIC program, including, but not limited to, the permitting of a number of injection wells in locations not exempted from the Safe Drinking Water Act, even though many meet the criteria for exemption. Their correspondence covers many important facts about, and objectives for, the Division's Class II UIC program.

This report addresses the following:

A. An overview of the UIC Program as mandated by state and federal statutes and regulations;
B. A summary of the data requested in items (1) through (5), above, broken out by calendar year for 2011 through 2014
C. A description of legislative and regulatory developments per item (6)
D. A summary of the detailed program assessment (item (7)) focused upon issues with the program in District 1 (the Los Angeles Basin area), one of the Division's busiest regulatory regions, with full report enclosed as Appendix 1
E. A summary of the results of discussions between the Division, State Water Resources Control Board, and the United States Environmental Protection Agency (U.S. EPA) designed to rectify certain UIC program shortfalls, with key correspondence included as Appendix 2 to this report
F. A concluding summary table rounding up significant known issues and the fixes being pursued for each

A. OVERVIEW OF THE REQUIREMENTS OF CALIFORNIA'S CLASS II UIC PROGRAM

The Division's mission requires it to prevent damage to life, health, property, and natural resources, while also encouraging the wise development of oil, gas, and geothermal resources to increase the ultimate recovery of underground hydrocarbons and geothermal resources. The Division is charged with enforcing existing statutes and regulations as defined by State mandates, and exercising primary authority over Class II injection wells for enhanced oil recovery as delegated to it by the U.S. EPA. The Division does this through the issuance of permits covering all forms of drilling, reworks, and abandonment for wells, including orphan and idle wells throughout California.

Injection wells have been an integral part of California's oil and gas operations for nearly 60 years. There are approximately 55,000 oilfield injection wells operating in the State. These include enhanced oil recovery (EOR) wells used to increase oil recovery through sustained injection or reinjection of large volumes of fluids, and wells devoted to the disposal of the "produced water" that emerges from hydrocarbon deposit areas simultaneously with, and commingled with, the production of oil and natural gas. About 75 percent of California's oil production of 600,000 barrels of oil per day (35 percent of California's daily petroleum use) results from deployment of EOR methods such as steam flood, water flood, and natural gas injection.

As a result of the maturity of California's oil fields, for every barrel of oil extracted, over 15 barrels of water are produced along with the oil. Of this amount, roughly two-thirds is returned to oil-bearing reservoirs for enhanced production and reservoir pressure balance. Of the remaining water, over 25,000 acre-feet (nearly 9 billion gallons of water) is cleaned sufficiently that when blended with other water it is safe and usable for agriculture. Some of the produced water is cleaned and released for the benefit of critical habitats. Some is retained and employed for productive uses within the oil fields (for example, cementing, well maintenance, and well stimulation). That water for which other uses cannot be found is disposed of in the State's approximately 1,800 Class II injection wells.

Produced water may only be injected into areas underground that (1) contain no water at all, (2) have water containing more than 10,000 mg/L of total dissolved solids (TDS), or (3) have been exempted from the federal Safe Drinking Water Act (SWDA) because they are too contaminated and/or too deep for economical beneficial use. The premise is that some water underground is associated with chemicals – including hydrocarbon deposits – that make the native water unsuitable for domestic consumption. Thus, a key part of the UIC Program involves reviewing permit proposals asserting that certain locations and depths are appropriate for injection because they target exempt aquifers, zones without any native water, or zones excluded from the SDWA owing to their high salt content or other contaminants.

In 1983, the U.S. EPA, under the federal Safe Drinking Water Act, delegated to the Division primary authority – primacy – to regulate wells injecting of fluids resulting from oil and gas extraction, or "Class II" wells. The Division's Class II UIC program is monitored by the U.S. EPA. In other states lacking the primacy delegation, the U.S. EPA regulates Class II injection directly.

The main features of the Division's Class II UIC program include permitting, inspection, enforcement, mechanical integrity testing, plugging and abandonment oversight, data management, and, increasingly, public outreach. In accordance with the 1983 primacy agreement between the Division and the U.S. EPA, the Division's Class II program is compensated annually based on the number of Class II wells. Although the Division has received close to $500,000 from the U.S. EPA in each of the past five years for managing the UIC program, this is only a small fraction of the funding required to manage the program on behalf of the U.S. EPA. The full cost of managing this program exceeds approximately $25 M annually.

Operators and owners of Class II injection wells must file for a permit with the Division before any drilling, well re-work, or plugging and abandonment can take place. Permits to drill are sought from the Division by submitting a Notice of Intent. When approval for a new project is sought, the project must be approved before individual permits can be issued. The proposed injection project is evaluated by Division engineers and reviewed by the appropriate Regional Water Quality Control Board.

The UIC Program strives to achieve "zonal isolation" of proposed injection. "Zonal isolation" is the concept that fluids injected into a geologic zone or strata will remain in that zone and not migrate into a different zone. In part to ensure zonal isolation, State regulations beginning with California Code of Regulations Section 1724.6 et seq., require that plugged and abandoned wells in the area will not have an adverse effect on the project or cause damage to life, health, property, or natural resources, and that formation pressures are not exceeded to the extent that damage occurs. Meeting these regulations requires extensive reviews of formation geology and of existing wells nearby that are drilled into the injection zone, to determine if they are compromised or could otherwise become a conduit for injection fluid into a different zone.

Well integrity is required for all injection wells. All wells must meet casing requirements aimed at achieving zonal isolation. Metal casing is placed in the drilled hole (wellbore), and cement is added in the space between the casing and the hole (annulus) to bond the metal casing to the surrounding rock and/or aquifer through which the well has been drilled. This annular cement creates a seal or barrier that prevents fluids from moving up or down the wellbore. Casing must be of specified strength, competence, and length and extend through all oil and natural gas formations that contain not just hydrocarbons, but also water. In the case of UIC wells, there are high standards for mechanical integrity testing, owing to the importance of well construction and well integrity in achieving zonal isolation.

When an operator seeks to operate an injection well, there are two approvals that must be received prior to injection. The first is a "project" approval. A "project" under UIC consists of many wells, sometimes as many as 200 wells, in an injection-production system. Some of the wells are injection wells, others will be production wells, and some wells are often converted from one use to another as a field matures. The "project" proposal includes evaluation of the geology of the area to be subject to injection and production operations. It also must include review of the construction of neighboring wells and the ability of the geologic structures to contain injection fluid within the intended injection zone.

Approval of a "project" under the UIC program, however, is not the same as the approval of a well. An operator must also submit a permit request for each well. These permits may be submitted simultaneously with the "project" or may be submitted later as the operator continues to develop the production from the project area. The well permit addresses the well's construction and how that construction meets the well construction standards.

In 2011, the Department requested, and U.S. EPA contracted for, an audit of the UIC Program. That audit was the first comprehensive evaluation of the federally-delegated UIC Program in its nearly 30-year history. The Department has been engaging in ongoing review with the U.S. EPA and the State Water Resources Control Board since then. To date, the review has found inconsistent practices among district offices, unclear and inconsistent histories about aquifer exemptions, inconsistent application of area reviews under project permitting, and aging regulatory constructs that need to be updated to match current oil production methods.

These shortcomings of the UIC Program have resulted in a relatively small number of wells being permitted where they should not have been in the context of over 55,000 injection wells permitted in the State. The Department and the State Water Board are reviewing the siting, as permitted, of hundreds of existing injection wells. Out of more than 500 injection wells identified as posing a potential risk of contamination to potential sources of drinking water, 23 have been shut-in (11 in the summer 2014, and 12 more in March 2015).

Limited testing of nearby water supply wells has shown no contamination of adjacent water supplies. However, this review is continuing, and will be followed up with a finely-detailed project-by-project review of each UIC project, regardless of location, encompassing the more than 55,000 UIC wells in California under the terms of the UIC action plan developed jointly with U.S. EPA, the Department, and the State Water Board. If and when additional high-risk wells are located, they will be shut in quickly as has been current practice.

B. Data Specifically Requested Under SB 855

1. Permitting: Numbers and Timing

SB 855 requests data on the annual number of underground injection permits issued by the department and the average length of time to obtain a permit from date of application to the date of issuance. (SB 855, § 35, subd. (a)(1)-(2).) That information is as follows:

- For 2011, the Department received 11 applications for UIC Projects. Six projects were approved in that year, and 4 were disapproved or cancelled. Three hundred individual injection well applications were received. The average time to permit a well during that year was 22 days, with a median permit processing time of 14 days.

- For 2012, the Department received 30 applications for UIC Projects. Twenty projects were approved in that year, and 2 were disapproved or cancelled. Three hundred thirteen individual injection well applications were received. The average time to permit a well during that year was 19 days, with a median permit processing time of 14 days.

- For 2013, the Department received 62 applications for UIC Projects. Thirty-one projects were approved in that year, and 1 was disapproved or cancelled.

Three hundred ninety-one individual injection well applications were received. The average time to permit a well during that year was 14 days, with a median permit processing time of 11 days.

- For 2014, the Department received 41 applications for UIC Projects. Thirty-six projects were approved in that year, and 1 was disapproved or cancelled. Three hundred twenty-three individual injection well applications were received. The average time to permit a well during that year was 11 days, with a median permit processing time of 11 days.

The table below summarizes the above data and includes for reference the permitting time for all wells, not just for UIC wells.

Year	UIC Projects			Well Permits			
				All Wells		UIC	
	Received	Approved	Disapproved / Cancelled	Ave. Time to Issue Permit	Median	Ave. Time to Issue Permit	Median
2011	11	6	4	16	13	22	14
2012	30	20	2	15	14	19	14
2013	62	31	1	12	10	14	11
2014	41	36	1	12	11	11	11

The number of permitted projects appears to show a significant increase in 2012. In part, this is an artifact of the specific interval in time – a longer time series shows ups and downs in the annual number of permitted projects. In addition, the increase represents increased Division capacity with the hiring and training of staff following approval of additional positions for UIC in the FY 2011-2012 budget. Furthermore, it is worth noting only 5 projects were approved in the latter half of 2014, when UIC staff were focused on wells reviews and activities related to the engagement with U.S. EPA for UIC compliance.

2. *COMPLIANCE*

SB 855 requests reporting the number and description of permit violations identified and the number of enforcement actions taken. (SB 855, § 35, subd. (a)(3)-(4).) For this report, permit violations are aggregated into these six categories:

1) Injection without a completed project approval
2) Failure to address mechanical integrity issues identified by the Division
3) Failure to operate under permitted conditions, such as rate or pressure, as identified by the Division
4) Ineffective/insufficient plugging identified during witnessing or inspection
5) Monitoring and Reporting Violations – failure to properly and/or timely report information
6) Other violations

Enforcement actions are aggregated into the following categories:

1) Notices of Violation (NOV) – advises operator of failure to comply with Division regulations and requires operator to remedy
2) Administrative Orders – issued if/when operator fails to remedy NOV issues and can include shut-in of well
3) Well shut-ins – operator shuts-in well under agreement with Division as an expedited version of NOV – Administrative Order process
4) Pipeline severances – direction to disconnect injection piping to a shut-in well to ensure compliance with order to cease injection; may be issued when plugging and abandonment is not required or advisable
5) Other enforcement actions

The numbers of violations and enforcement actions for calendar years 2011 through 2014 are as follows:

	Year			
	2011	**2012**	**2013**	**2014**
Permit Violations Identified				
Unauthorized Injection	9	323	12	17
Mechanical Integrity	227	29	85	110
Operations and Maintenance	15	106	763	822
Plugging and Abandonment	0	10	1	2
Monitoring and Reporting Violations	672	72	69	122
Other Violations	2	2	24	0
Enforcement Actions Taken				
Notices of Violations	235	133	938	764
Administrative Orders	0	0	11	11
Well Shut-ins	662	6	3	11
Pipeline Severances	13	3	0	0
Other Enforcement Actions	22	16	43	120

As with the number of projects permitted, interpretation of these numbers reflects a variety of actions taken by the Division and must be viewed in context. Owing to insufficient staffing, the Division has focused staff time on specific issues that change from year to year. In some cases, the numbers reflect enhanced efforts by the Division to educate and ensure compliance by the industry about revised regulatory frameworks. In some cases, the numbers reflect an increase or decrease in the number of new wells drilled versus reworking and recompleting wells in new zones, etc. as well as ups and downs in the price of oil that affect specific industry activities and result in a varying set of violations.

3. *STAFFING*

SB 855 further requests a report on staffing changes in the UIC Program during the reporting period. (SB 855, § 35, subd. (a)(5).) When the Department provided the January 2011 report on 2010 activities, the hiring for positions authorized in the FY2010-2011 Budget was not complete. Therefore, this report includes reference to changes in staffing since those positions were authorized.

We defined “staff changes” to mean the number of positions authorized at the beginning of a fiscal year that were filled by the end of that fiscal year. In some cases, newly-authorized positions became opportunities for advancement of internal candidates. When an internal candidate fills a newly-created position, the Department must engage in a secondary process to fill the vacant position created by the promotion/transfer of the internal candidate into the new position. In this manner, some vacancies consistently exist within the Department across all program areas.

The Fiscal Year 2010-2011 Budget authorized 17 positions for enhancement of UIC Program implementation. Those positions were all filled by late June 2011.

For the Fiscal Year 2011-2012 Budget, the Department proposed 36 new positions in the Division of Oil, Gas, and Geothermal Resources, 11 of which were to be dedicated to UIC and related enhanced oil recovery (EOR) permitting. The proposal was made late in the budget process during the May budget revision. The Legislature approved half of the 36 positions requested, directing the Department to resubmit any of the other 18 positions for consideration through the routine annual budget process that starts with the release of the Governor’s proposed budget on January 10 of each year. Of these 18 approved positions, many were filled in the FY2011-2012 period, but 5 were not filled until the next FY. These were Associate Oil and Gas Engineers, for which recruitment had been very difficult given competition for their expertise in the private sector.

For the Fiscal Year 2012-2013 Budget, the Department requested the 18 positions that remained from the original Fiscal Year 2011-2012 request. These were approved by the Legislature. All 36 positions – including the 11 positions identified specifically for UIC and EOR – authorized in this fiscal year and the prior fiscal year were filled prior to the end of the Fiscal Year 2012-2013 Budget.

The Fiscal Year 2014-2015 Budget included 65 positions across the Department for implementation of Senate Bill 4 (Pavley), a bill related to well stimulation practices such as hydraulic fracturing that required the development, now nearing completion, of a new, comprehensive regulatory program. As a consequence, none of these positions are dedicated to UIC program work.

Over the arc of this reporting period, the number of positions requested show two consistent features – (1) recognition by Division leadership that additional resources were needed to manage the UIC regulatory program, and (2) the number of staff needed was uncertain and therefore consistently underestimated. Both result from the growing realization of the number and complexity of problems being addressed as identified in the Horsley-Witten audit, and the growing magnitude of the challenge of managing these problems.

C. New Legislation and Regulations

SB 855 requests a description of any state or federal legislation, administrative, or rulemaking changes to the program. (SB 855, § 35, subd. (a)(6).)

1. *Legislation*

Senate Bill 83 (Committee on Budget and Fiscal Review, Chapter 24 Statutes of 2015) establishes an aquifer exemption proposal process in which the Division coordinates with the State Water Resources Control Board on a state level to conduct a public evaluation of aquifers prior to submitting exemption proposals to the United States Environmental Protection Agency for consideration. The bill also establishes biannual reporting requirements for the Division and Water Board. Beginning January 30, 2016, the Division and the Water Board must provide the following information to the Legislature:

1. The number and location of underground injection well and permits and project approvals issued by the Department, including permits and projects that were approved but subsequently lapsed without having commenced injection.
2. The average length of time to obtain an underground injection permit and project approval from date of application to the date of issuance.
3. The number and description of underground injection permit violations identified;
4. The number of enforcement actions taken by the department.
5. The number of shut-in orders or requests to relinquish permits and the status of those orders or requests.
6. The number, classification, and location of underground injection program staff and vacancies.
7. Any state or federal legislation, administrative, or rulemaking changes to the program.
8. The status of the review of the underground injection control projects and summary of the program's assessment findings completed during the reporting period, including any steps taken to address identified deficiencies.
9. A summary of significant milestones in the compliance schedule agreed to with the USEPA, as indicated in the March 9, 2015, letter to the Division and SWRCB from the USEPA, including, but not limited to, regulatory updates, evaluations of injection wells, and aquifer exemption applications.
10. Progress addressing the program's assessment findings and delivery of that report to the fiscal and relevant policy committees of each house of the Legislature.

Finally, SB 83 requires the Secretary for the California Environmental Protection Agency and the Secretary of the Natural Resources Agency to appoint an independent review panel, on or before January 1, 2018, to evaluate the regulatory performance of the Division's administration of the UIC Program, and to make recommendations on how to improve the effectiveness of the UIC Program, including resource needs and statutory or regulatory changes, as well as UIC Program reorganization, including consideration of transferring administration of the program to the State Water Board.

2. *Regulations*

The chief development in this area has been the Division's adoption of injection compliance regulations. These emergency regulations and proposed permanent regulations provide that if operators injecting in identified aquifers fail to obtain an aquifer exemption duly issued by the U.S. EPA under the Safe Drinking Water Act by specified dates, the injection activity must cease. The key deadlines in both the emergency and proposed permanent regulations are as follows:

- October 15, 2015: injection must cease in all non-exempt, non-hydrocarbon-bearing aquifers with water less than 3,000 mg/L TDS unless an aquifer exemption duly issued by the U.S. EPA has been obtained (Cal. Code Regs. Title 14, § 1779.1, subd. (a)(1)).

- December 31, 2016: injection must cease in eleven aquifers historically treated as exempt unless the aquifer has been duly exempted by the U.S. EPA (Cal. Code Regs. Title 14, § 1779.1, subd. (b)).

- February 15, 2017: Injection must cease into aquifers between 3,000 mg/L and 10,000 mg/L TDS unless a duly-issued exemption is obtained. (Cal. Code Regs. Title 14, § 1779.1, subd. (a)(2), (3)).

The Division is currently conducting public workshops regarding the permanent regulations.

Additionally, the Division will begin work this fall on a series of other regulation packages described more fully in the joint letter of the Division and State Water Board on July 15, 2015.[1] (See also summary, below.)

[1] See Appendix 2, July 15, 2015 letter, Attachment 2, *Plan for Class II Program Improvements*, pp. 11-13.

D. Program Assessment: The Monitoring and Compliance Unit Report on District 1.

SB 855 requests a description of the findings of a program assessment (SB 855, § 35, subd. (a)(7)), and a report on the action plan developed to address the program assessment findings and its efforts to implement the plan. (SB 855, § 35, subd. (b).)

In early 2011, the Division established a Monitoring and Compliance (MC) Unit to assess the Division's management of its UIC program, adherence to state and federal requirements, internal record-keeping, and to generally evaluate program performance. The Unit is comprised of one Senior Oil & Gas Engineer and three Associate Oil & Gas Engineers. The new Senior Oil & Gas Engineer overseeing this unit began February 1, 2011, with the Associate Oil and Gas Engineers being hired over the next several months.

The MC Unit has two functions: to monitor Division programs, and to act as a team to provide resource assistance. The MC Unit has now looked in-depth at the UIC program in District 1 (Cypress, California – Los Angeles Basin). Its report, *Underground Injection Control Program Assessment Report, District 1: Determinations and Recommendations* is now complete, and is included with this report as Appendix 1.

The evaluation methodology used in the Program Assessment Report for District 1 was based on the selection and analysis of sample populations representing UIC application completeness, project files management, project approval letters, area of review (AOR), UIC well monitoring program practices, and annual project reviews. To the extent possible, program reviewers selected sample data from different historical intervals for evaluation against current program standards.

The Program Assessment Report for District 1 identifies problems whose root cause can be traced to the issues noted in the transmittal letter, including a shortage of Division staff, inadequate data management systems, and a lack of uniform staff training with regard to file handling and data entry. Lack of organization was noted in the handling and storage of paper files, and project approval letters were confusing, information-deficient, overly generic, or simply absent.

Deficient or Absent AORs. In 2012, owing to an insufficient number of properly trained staff, a decision was made that AORs could be deferred until after the commencement of injection. This policy was instituted based on two assumptions: (1) that AOR evaluations would be performed during the annual project review process, and (2) that the subject fields had previously undergone an appropriate AOR process. However, given the number of uncompleted AOR evaluations, and issues with annual reviews (discussed below), these conditions were not met in all cases.

Well Monitoring to Ensure Zonal Isolation. The goal of the well monitoring program is to ensure that injected fluid does not migrate out of the approved zone(s) of injection. To ensure this isolation, the Division employs a well monitoring program that includes establishing a maximum allowable surface injection pressure (MASP), and requires mechanical integrity tests (MITs), including standard annular pressure tests (SAPTs) and radioactive tracer (RA) surveys, of injection wells.

Evaluation of the adequacy of the District's well monitoring program revealed that although step-rate-tests (SRTs), used to derive the MASP, generally met current industry standards, few SRTs met U.S. EPA standards. However, as a result of minor changes in the Division's procedural practices and data capture, these deficiencies were corrected.

MIT Tests. Evaluation of MIT surveys was generally thorough in District 1. In cases of a failed test, operators were required to remediate and retest the well to obtain a passing MIT. However, data entry fields for these tests were frequently left blank, or incorrectly entered in the Division's California Well Information Management System database. This indicates that the Division's data quality control and quality assurance need to be improved and that more robust staff training is necessary.

Annual Reviews. The Primacy Agreement requires that all existing Class II projects in California be reviewed annually. Our reviews found the state has not met this obligation in District 1. Moreover, a review of the District's active project list revealed that the majority of projects have not been reviewed since 2007.

These and other findings are set forth in detail in the MC Unit's full report, enclosed herewith as Appendix 1.

E. JOINT EFFORTS OF THE DIVISION, STATE WATER RESOURCES CONTROL BOARD, AND U.S. EPA TO IMPROVE THE DIVISION'S REGULATION OF CLASS II INJECTION

The Division, State Water Resources Control Board, and U.S. EPA have been meeting regularly to put in place a plan that addresses some of the concerns with the program as a whole that the Legislature had when it passed SB 855. The Division and U.S. EPA had been corresponding occasionally since the 2011 U.S. EPA's Horsley-Whitten report – an audit of the Division's overall performance of its Class II UIC responsibilities. In mid-2014, following revelations of injection wells being permitted with unclear or absent exemption status, the Division and U.S. EPA meetings took on a new urgency. The State Water Resources Control Board, as the agency with statutory review authority for injection well permits, joined the effort.

In letters and meetings between the State (the Division and State Water Resources Control Board) and U.S. EPA, the three-agency group developed a plan for the Division to close down wells and improve and modernize its UIC practices. Though the plan has not as yet been reduced to a single document, its various components appear in five key letters between the State agencies and U.S. EPA. This correspondence, and a current summary table of all of the deadlines agreed to by the agencies, appears as Appendix 2 to this report, *Interagency UIC Program Improvement Planning: Major Correspondence and Deadlines.*

The plan consists of four major efforts to be conducted concurrently. First, and of highest priority, has been the ongoing review of permits for hundreds of individual injection wells in potentially unsuitable areas, with closures of wells as necessary. Second, the Division has committed to conduct a project-by-project review of each UIC project. Third, this fall, the Division will embark on a series of rulemakings to modernize and enhance the State's regulatory framework. And fourth, the Division and the administration are developing a modern well and data management system to handle all of the Division's records and data.

The four components of the plan and its current status are summarized below.

1. *Well Review and Aquifer Exemptions*.

The Division and State Water Board have been systematically reviewing injection wells that may have been sited inappropriately. From the beginning of the effort last year, the Division has placed first priority on the review of disposal wells that may pose an immediate risk to waters of beneficial use, and has agreed to order the closure of, or obtain operator permit relinquishments for, wells appearing to pose such a risk.[2] As of today, the Division has secured the closure of 23 such disposal wells.[3]

The remaining wells have been placed into three priority categories for review and action:

> Category 1 Wells: Class II water disposal wells injecting into non-exempt, non-hydrocarbon-bearing aquifers or the 11 aquifers historically treated as exempt
>
> Category 2 Wells: Class II enhanced oil recovery (EOR) wells injecting into non-exempt, hydrocarbon-bearing aquifers
>
> Category 3 Wells: Class II water disposal and EOR wells that are inside the surface boundaries of exempted aquifers, but that may nevertheless be injecting into a zone not exempted in the primacy agreement[4]

The Division has also agreed to set deadlines for operators to either shut in or obtain exemptions for these wells as required. These regulations may be found on the Department's web site at:

http://www.conservation.ca.gov/dog/general_information/Pages/UndergroundInjectionControl(UIC).aspx

Emergency regulations, and follow-up permanent regulations require the shut-in of the following wells, or the securing of an exemption from U.S. EPA, by the following dates:

> October 15, 2015: Wells injecting into non-hydrocarbon-producing zones of less than 3,000 mg/L total dissolved solids (TDS) (Cal.Code Regs., tit. 14, § 1779.1(a)(1))
>
> December 31, 2016: Wells injecting into 11 specified aquifers historically treated as exempt (Cal.Code Regs., tit. 14, § 1779.1(b))
>
> February 15, 2017: Wells injecting into non-hydrocarbon-producing zones of between 3,000 and 10,000 TDS (Cal.Code Regs., tit. 14, § 1779.1(a)(2))
>
> February 15, 2017: Wells injecting into hydrocarbon-producing zones of less than 10,000 TDS (Cal.Code Regs., tit. 14, § 1779.1(a)(3))

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[2] See Appendix 2, February 6, 2015, letter, Enclosure D: More Detailed Look at Administrative Concepts, at p. 1.

[3] See Appendix 2, May 15, 2015, letter, Attachment H: Orders and Relinquishments.

[4] See Appendix 2, February 6, 2015, letter, pp. 3-4.

Again, it should be stressed that this prioritized set of deadlines, now committed to regulation, guides the ordering of the Division's well review process but does not supplant or otherwise delay the Division's ability to take action on wells of immediate risk. The Division remains empowered to close wells of greatest risk throughout this process, either by securing the operator's voluntary relinquishment of the permit, or by administrative order.

With respect to aquifer exemptions, which are determined by the U.S. EPA, the Division is collecting information from operators interested in pursuing exemptions, and will take each operator data package through a process that will culminate either in a determination by the State (both the Division and State Water Board) to inform the U.S. EPA of the State's opinion that exemption criteria appear to be presently met, or that there is insufficient information for such a conclusion to be drawn. The U.S. EPA has final authority to declare an aquifer exempt going forward.[5]

2. *Project-by-Project Review of Injection Project Approvals.*

The Division has also committed to begin conducting individual project reviews designed to find missing data, identify UIC compliance issues, and to compare existing project approvals with current conditions in the field.

During this process, operators will be required to provide missing data, and the Division will reevaluate the project based on all relevant regulations, mandates, and policies, including demonstration of zonal isolation of injected fluids. Projects will be reapproved, modified, or cancelled as appropriate.[6]

3. *New Regulations and Program Revisions.*

In addition to the regulations described above calling for the shut-in of wells in the absence of a determination by the U.S. EPA that a portion of a geologic formation is not covered by the SDWA (either because it does not contain water or does not contain water of quality suitable for use), the Division has also committed to doing other new rulemaking. Many state regulations governing underground injection control are obsolete, deficient, or simply unable to address current industry practice. Therefore, beginning this fall, the Division will undertake a series of rulemakings to improve the State's regulatory framework so as to address these issues.

New regulations will address a myriad of issues, such as zonal isolation, the quality of water to be protected, well construction practices, cyclic steam operations, maximum allowable surface pressure, ongoing project review, and idle well standards and testing.[7]

New business practices, apart from those expressed in regulation, will include new staffing, compliance monitoring, and business process reviews.[8]

4. *Development of A Modern Well and Data Management System.*

[5] See Appendix 2, July 15, 2015, letter, Attachment 2, Plan for Class II Program Improvements, p. 9.
[6] See Appendix 2, July 15, 2015, letter, Attachment 2, Plan for Class II Program Improvements, pp. 6-9.
[7] See Appendix 2, July 15, 2015, letter, Attachment 2, Plan for Class II Program Improvements, pp. 11-12.
[8] See Appendix 2, July 15, 2015, letter, Attachment 2, Plan for Class II Program Improvements, pp. 10-11.

The Division has committed to U.S. EPA that it will pursue a vastly improved data management system.[9] The improvement of the Division's data management system is now under way as a result of funding forthcoming in the FY 15-16 Budget. The development and implementation of this system is central to the improved performance of every aspect of the Division's work – regulatory compliance and effectiveness, transparency, and support of all stakeholders.

Finishing every piece of the UIC improvement plan submitted to the U.S. EPA will consume 3-4 years. However, as each component piece is completed, tangible improvements in the Division's performance of its mission will follow. Such changes will be supported by the development of sustained, comprehensive training programs to support the process of constant internal review and adjustments for continuous improvement of the execution of the Division's responsibilities.

CONCLUSION: PROBLEMS AND SOLUTIONS: POINT-BY-POINT DESCRIPTION OF SIGNIFICANT TROUBLE SPOTS AND EFFORTS BEING MADE TO ADDRESS EACH

Monitoring and Compliance UIC Review

Findings	Corrective Actions	Status
There has not been a consistent standard of practice for collecting and maintaining information about projects. - Record-keeping has been poor. Many project files – mostly from previous decades – are missing information that is required by regulations and is also necessary to fully monitor, inspect and evaluate a project. - Project files are not centralized. Data and records are poorly organized and often located in multiple places. - Project files are not digitized.	1. As part of the Division's statewide project-by-project review beginning in September 2015, field inspectors and staff will collect all missing required data plus any additional data necessary to confirm the confinement of injected fluid. 2. Project-by-project review guidance document creates a standard of practice for record-keeping to achieve consistency at the district and statewide levels. All project files will have a checklist to ensure all data has been received and evaluated. 3. As the Division restructures and acquires new staff, it will institute systematic training among new and existing staff on the new standards of practice. 4. Build a publicly accessible and fully searchable online database that integrates paper files from multiple past decades with modern data collection practices going forward, and also identify data gaps.	Prior to 2011, 56% of the "pre-primacy" projects had incomplete data. After the letter of expectations in 2011, and the Division obtained missing data, the percentage of projects missing data has dropped to 17% in District 1. Project applications are now returned to operators with a request to provide all missing information before they will be considered. Meetings with operators have been conducted to convey expectations to operators. The Legislature allocated $10 million in the 2015-16 budget for the Division to expedite construction of a data system by 2017-2018; Stage-Gate process under way.

[9] See Appendix 2, February 6, 2015 letter, p. 10.

Project Approval Letters (PALs) are incomplete, unclear and inconsistently modified. - Essential elements are often missing or difficult to discern, such as type of project or the injection zone. - Many projects have multiple injection zones and permit times, all under the same PAL. - Some PALs lack clarity as what operations were approved and under what conditions the project is required to operate.	1) With the Project-by-Project review, new PALs will be written to clearly identify the paramenters of the project. 2) If necessary, projects may be split into multiple projects to address the specifics in the field. 3) New PALs will be written to address specific project conditions, including a list of wells in the project. 4) A guidance document is being prepared to provide clear direction regarding the permitting of a UIC project and will accompany additional technical training.	Project-by-project review will commence in September; schedule for completion in each District is given in the document submitted to U.S. EPA, "Plan for Class II Program Improvements," attachment 2 of submittal to US EPA on July 15, 2015.
Problem wells located within the Area of Review could potentially provide a conduit for injected fluid to migrate.	1) The Project-by-Project review is designed to ensure all required data is obtained and evaluated. This includes the many issues identified in the review concerning well construction and associated casing diagrams. 2) Problem wells will be remediated or the project modified accordingly. 3) An assessment of the zone of endangering influence will be performed to determine the extent of impacts caused by injection. 4) New regulations addressing well construction are being developed. 5) The Monitoring and Compliance team is gaining additional staff to increase the oversight of the work being completed in the District offices.	Publicorkshops initiating phase 1 of two phases of rulemaking were held in September 2015. Phase 1 included: standards for zonal isolation, well construction standards, regulatory requirements for cyclic steam, regulatory requirements for cyclic steam extraction from diatomite, standards for establishing maximum allowable surface pressure for injection operations.

Inadequate number of step rate testing performed. Mechanical Integrity Tests (MIT) not being performed or being performed but past due. Poor tracking system does not provide for alerts when tests are due.	1) As part of the Project-by-Project review additional testing will be required where either tests were not conducted in the past or there is concern about the validity of the data. 2) A new data management system is being developed to better track test results and to aid in the field monitoring of actual injection pressure being utilized in the wells. 3) The guidance document being prepared for UIC approvals will include strict guidelines for step rate testing in compliance with U.S. EPA standards.	Guidance document requires current, accurate test results before a PAL can be issued or reissued.
Lack of consistency of annual project reviews. In addition, over time the Division substituted a questionnaire instead of a face-to-face meeting with operators to discuss projects.	1) Annual project reviews will be addressed in the Project-by-Project review. Once the missing data are collected and the project files are organized, project reviews will be performed annually and more efficiently. 2) New regulations will outline the requirements for an annual project review.	Hiring of UIC staff positions funded in the 2015-2016 budget to bolster the resources needed to conduct the annual reviews and other UIC related duties is under way. Guidance document for project-by-project review specifies documents and their order in a project file. The review will also require extensive interactions, now under way, with operators to collect missing data, remediate past-due tests, and reevaluate the project.

Department of Conservation,
Division of Oil, Gas, and Geothermal Resources

Underground Injection Control Program Assessment Report, District 1: Determinations and Recommendations

Appendix 1 to Report to the California Legislature under SB 855 (2010)

Monitoring and Compliance Unit
May 2015

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VII. Tables

LIST OF ACRONYMS AND ABBREVIATIONS

AOR	Area of Review
APR	Annual Project Review
BCP	Budget Change Proposal
BFW	Base of Fresh Water
CalWIMS	California Well Information Management System
CBL	Cement Bond Log
CCR	California Code of Regulations
CFR	Code of Federal Regulations
Department	Department of Conservation
Division	Division of Oil, Gas, and Geothermal Resources
GS	Gas Storage
ISIP	Instantaneous Shut-in Pressure
MASP	Maximum Allowable Surface Pressure
MC	Monitoring and Compliance
Mg/l	milligrams per liter
MIT	Mechanical Integrity Test
N/A	Non-applicable
NEA	No engineer available
NEI	Not Enough Information
P&A	Plugged & Abandoned
PAL	Project Approval Letter
PC no.	Project Code Number
PPM	Parts per million
Psi/ft	Pounds per square inch per foot
RA	Radioactive tracer
SAPT	Standard Annular Pressure Test
SB4	Senate Bill 4
SB858	Senate Bill 858
SDWA	Safe Drinking Water Act
SRT	Step-Rate Test

TDS	Total Dissolved Solids
TIZ	Top of Injection Zone
TVD	True Vertical Depth
UIC	Underground Injection Control
U.S. EPA	United States Environmental Protection Agency
USDW	Underground Source of Drinking Water
WD	Water Disposal
WF	Water Flood
ZEI	Zone of Endangering Influence

I. EXECUTIVE SUMMARY

The Division of Oil, Gas and Geothermal Resources (Division) has conductedan in depth review and evaluation of the Underground Injection Control (UIC) Program of the District 1 office in Cypress, California (Los Angeles Basin). The objective of the review was to evaluate the implementation of the UIC program in the Division's District 1 (Cypress) in accordance with Division mandates, regulations and policies. As a result of this review, performance issues have been identified that can be mitigated through programmatic improvements designed to move the District and the Division towards full compliance with UIC Program standards.

Program evaluation methodology involved analyzing sample populations of UIC applications, project files management, project approval letters, area of review (AOR) evaluations, UIC well monitoring program practices, and annual project reviews (APR). To the extent possible, program reviewers selected sample data from different historical intervals for evaluation against current program standards.

In 1983, the United States Environmental Protection Agency (U.S. EPA) granted the Division "primacy" -- primary authority for the management and enforcement of the UIC Class II Program in California. This authority gave the Division primary responsibility for protecting underground sources of drinking water (USDWs). In general, we found a significant increase in completed injection applications consistent with a pattern of improved Division practices following primacy.

The UIC program evaluation found deficiencies in the District 1 UIC program related to the shortage of Division staff, inadequate well and data management systems, and a lack of uniform staff training with regard to file handling and data entry. Lack of organization was noted in the handling and storage of paper files, and project approval letters (PALs) were confusing, information-deficient, overly generic, or incomplete.

AOR evaluations need to be conducted more consistently. While the performance of required AOR evaluations increased significantly following the granting of primacy in 1983, a large number of evaluations remain to be performed.

In 2012, District 1 initiated a Division wide deferral policy to allow for an AOR evaluation to occur along with the annual project review. This policy was based on two assumptions: 1) that AOR evaluations would be performed during the APR process, and 2) that the subject oil fields had previously undergone an appropriate AOR process. However, analysis showed that the AOR evaluations were not up to date and there were deficiencies in the annual reviews.

The Division employs a well monitoring program to ensure "zonal isolation to migrate against the potential for injected fluids to migrate out of the intended zone or formation. To ensure zonal isolation, the Division requires establishing a maximum allowable surface injection pressure. Maximum Allowable Surface Pressure (MASP) is determined by a step-rate test

(SRT), and requires mechanical integrity tests (MITs), including standard annular pressure tests (SAPTs) and radioactive tracer (RA) surveys, of injection wells.

Our review of the District's well monitoring program revealed that while SRTs used to derive the MASP generally met current industry standards, some SRTs were not completely consistent with EPA regulations. However, these problems have since been corrected through modification of procedures and improved data capture In addition, as a result of a backlog of regulatory actions, about 1/3 of the most recent required SAPT and RA surveys were past their current scheduled performance date.

District oversight of MIT surveys was generally thorough. In cases of a failed test, operators were required to remediate and retest the well to obtain a passing MIT, though the results were often not correctly entered in the Division's California Well Information Management System (CalWIMS) database.

The Primacy Agreement requires that all existing Class II projects in California be reviewed annually. The Division has generally not met this obligation because the magnitude of the effort requires additional staff, improved training, and better and more easily accessible records. In District 1, in depth review of the active project list revealed that a majority of projects have not been reviewed since 2007.

II. INTRODUCTION

General

Since 1983, the Division, part of the Department of Conservation (Department), has had primary authority to regulate Class II injection wells in California under the federal Safe Drinking Water Act (SDWA). That authority is carried out within the Division's UIC program.

In 2010, the Department and Division prepared a Budget Change Proposal (BCP) to augment the UIC permitting program. That effort coincidentally revealed some significant issues with program performance statewide. Subsequently, the Division created the Monitoring and Compliance (MC) Unit to evaluate regulatory compliance issues generally, and particularly with the UIC Program.

The MC Unit was tasked with evaluating and reporting on the strengths and challenges of the UIC Program in meeting the statutory and regulatory standards on which the program is based. These underlying standards consist of state statutes and regulations, the Primacy Agreement and Memorandum of Agreement with the U.S. EPA, and the Division's 2010 Letter of Expectations delivered to UIC staff. This report is focused upon the Division's Cypress field office, District 1, and identifies the manner in which key UIC Program components have been implemented there.

Understanding this report requires delineation of four major periods of significant regulatory changes to UIC program requirements. These are listed in Appendix A of this report and may be summarized as follows:

1. *Pre-Regulation to 1978.* Statutes and regulations prior to 1978 relied on requirements to prevent movement of fluid, chiefly water, into neighboring operators' hydrocarbon reservoirs.

2. *Regulations from 1978 to 1982.* In 1978, regulation section 1724 was added to require specific data be submitted with an application for injection project approval.

3. *The Initiation of Primacy,* 1983 to 2010. In 1983, the Division was granted primary authority ("primacy") from the U.S. EPA for the management and enforcement of the UIC Class II Program in California. This authority gave the Division, instead of the U.S. EPA, primary responsibility for protecting USDWs, meaning waters containing 10,000 milligrams per liter (mg/L) or less of total dissolved solids (TDS). This authority to protect USDWs required some program changes, including adding a two-part MIT procedure, a specific AOR evaluation prior to the project approval process, and clarification of how to protect waters with 3,000 mg/L TDS or less.

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4. *From 2010 to 2013*. In 2010, the Division prepared a Letter of Expectations to staff, clarifying certain aspects of the UIC program implementation. During this time, Division district offices were instructed to implement the Letter of Expectations during permitting and annual reviews of existing projects.

To the extent possible, program reviewers selected representative sample data from each of these historical time periods for evaluation against current program standards.

Purpose

The purpose of this review is to determine whether the Division UIC practices, including permitting, inspection, monitoring, well MIT, plugging and abandonment, enforcement, and data management practices, conform with UIC program standards as mandated.

Practical benefits of this report are expected to include improved APRs in accordance with State Senate Bill 855 (SB 855 [2010]), better compliance with mandated report requirements, and ultimately the adjustment of UIC projects going forward to meet current standards so the state is in full compliance with the Safe Drinking Water Act

Scope of Work & Audit Report Process

The scope of this analysis was patterned upon the Assessment portion, in Section II, of the Work Plan submitted with the 2010 Budget Change Proposal, which called for the following activities to be undertaken:

1. Evaluate a representative sampling of old projects that are in fields that were discovered in the 1930s and 1940s to determine if appropriate AORs were completed and to determine if potential conduits for the injection fluid were identified.

2. Evaluate a representative sampling of recent projects to determine if appropriate AORs were completed and to determine if potential conduits for injection fluid are present.

3. Evaluate a representative sampling of the records for annual project reviews to determine if they were performed and documented adequately to determine if the project was in compliance with the project approval.

4. Evaluate a representative sample of the Division's UIC well monitoring program to determine if adequate MIT surveys were conducted, evaluated, and documented to ensure mechanical integrity of the injection wells.

5. Evaluate a representative sampling of the Division's UIC monitoring program to determine if the MASPs were determined correctly and monitored to ensure compliance with the PAL.[10]

This analysis focused primarily on items 1 through 5, of the work scope items above Additional findings related to program compliance were also included. Additionally, while SB 855 and the 2010 Work Plan describe the need for a Division-wide evaluation, this analysis is limited to findings of UIC program issues for District 1 as a first step towards a Division-wide program review. District 1 was chosen as the first district office for review because of its high population density and urban setting, with corresponding higher risk to life, health and public resources. As of December 2013, District 1 had a total number of 268 injection projects, of which a total of 154 were active.

A team approach was used to conduct the assessment. Engineers were assigned to review specific program technical areas corresponding with their area of expertise. The MC Unit Review Team received training in advance of this analysis by assisting the Cypress, Bakersfield, and Orcutt offices with performance of AORs for proposed UIC projects for a year prior to in itiating this review.

Report Organization

This report is divided into the following sections: (A) UIC Project Applications, which looks at UIC application completeness, project files management, and PALs; (B) AOR Evaluations; (C) Maximum Allowable Surf ace Injection Pressure Calculations; (D) MIT; and (E) APRs.

Tabulated data summaries are presented at the end of the d ocument in the Tables section. **Appendix B** provides a simplified review of technical concepts and definitions related to oil and gas drilling and the UIC program useful for an understanding of concepts and terms used frequently in this report.

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[10] The BCP also specified a sixth and seventh activity, namely to evaluate whether the Division's UIC staff are appropriately educated, trained and have the necessary tools to enforce the SDWA in regards to Class II wells, and whether the Division has enough staff and resources to adequately enforce the SDWA in regards to Class II wells. These important areas of inquiry are not addressed in this report.

III. DETERMINATIONS AND RECOMMENDATIONS

A. UIC Project Applications

1. Application Completeness

Before an injection project can be approved, operators must submit an application package with data demonstrating that no damage will occur as a consequence of injection operations. Current UIC program standards require that every application received by the Division, whether for a new project or expansion of an existing injection project, must undergo an AOR evaluation to ensure zonal isolation in the area surrounding each injector, so that no injected fluids will migrate out of the approved injection zones. Zonal isolation determination requires an evaluation of the well construction of every well within an area surrounding the injector and a geologic demonstration that no conduits exist for fluid movement out of the intended injection zone. The list of data required with an injection project application under current program standards is detailed in the California Code of Regulations (CCR) section 1724.7, and includes, but is not limited to:

1. A description of the purpose of the project.

2. An engineering study that includes reservoir characteristics such as porosity and permeability of the formation, areal extent, average thickness, fracture gradient, original and present formation temperature and pressure, and original and residual oil, gas and water saturations.

3. A geologic study that includes structural contour maps drawn on a geologic marker at or near the top of each injection zone in the project area, an isopach map, a geologic cross section through at least one injection well, a representative electric log to a depth below the deepest producing zone that identifies all geologic units, formations, freshwater aquifers, and oil and gas zones.

4. Casing diagrams of all wells located in the area affected by the project. The casing diagrams must include cement plugs, and actual or calculated cement fill behind casing, and evidence that all plugged and abandoned wells will not have an adverse effect or cause damage.

5. An injection plan and map showing injection facilities, maximum anticipated surface injection pressure and daily rate of injection by well, a monitoring system to ensure that no damage is occurring and that fluid is confined to the zone.

6. The source and fluid analysis of the proposed injection fluid and the formation fluid, and the treatment of water to be injected.

7. Other data necessary for a complete review of the proposed injection operation. These data may include the results of injectivity tests and other formation tests to determine the ability of the formation to take fluids without fracturing.

The MC Unit Review Team conducted an evaluation of the UIC applications for each period against current standards. A sample of 52 injection project applications were reviewed for this evaluation; 25 applications were reviewed from pre-Primacy periods, and 27 from post-Primacy periods. **Table 1** and **Appendix B** of this report present, respectively, a brief summary and expanded discussion of these historical regulatory periods introduced in the preceding section.

Determinations

An analysis of UIC injection project applications in District 1 indicated that:

1. Early period UIC project applications were generally compliant with standards corresponding to the periods' application completion standards. Results of this evaluation are summarized in **Table 1** of this report.

2. Retaining incomplete project applications in a queue while requesting additional and/or missing data from the operator is inefficient and increases the amount of work and time required by District staff.

3. As shown in **Table 1**, 56% of the pre-Primacy injection projects were incomplete and 41% of approved post-Primacy injection projects were incomplete. Within the post-Primacy sample population, only 1 of the 6 (17%) post-Letter of Expectations UIC injection projects were incomplete.

4. While indicating a need for considerable improvement, these data suggest an improving trend in UIC application completeness over time.

Recommendations

The following program recommendations are based on general observations of application review practices in District 1.

1. To expedite the application process, operators should assume responsibility for ensuring that their injection project application contains sufficient and accurate engineering and geological information necessary to demonstrate to the Division's satisfaction that their project will operate in compliance with the UIC program requirements.

2. Incomplete applications received by the District should be promptly returned to the operator for completion, and not kept in a queue in the office as is the current practice.

3. As part of a project application package provided to operators, the application checklist should be updated to include the requirements of the CCR Division 2, Chapter 4, Subchapter 1 Sections 1724.7, 1724.8 and 1724.9 (Project Data Requirements), as well as updates resulting from the implementation of Senate Bill 4 (SB4 [2014] Well Stimulation and Treatment Regulations).

4. Applicants must provide the source of information and/or data contained in their project application.

5. Staff should crosscheck all the regulatory references, geological information, well construction, field and reservoir characteristics, plugging and abandonment plans, information about fracture gradient, proposed operating conditions, USDW definition, proposed construction and formation testing etc.

2. Project Files Management

The content of project applications should include: an engineering study; reservoir characteristics for each injection zone (porosity, permeability, average thickness, areal extent, fracture gradient, etc.); reservoir fluid quality data for each injection zone (oil gravity and viscosity, water quality and specific gravity of gas); casing diagrams, including cement plugs, actual or calculated cement fill behind casing of all idle, plugged and abandoned, or deeper-zone producing wells within the area affected by the project; a geologic study including structural contour maps drawn on a geologic marker at or near the top of each injection zone; an isopach map of each injection zone or subzone; geologic cross section through injection well; representative electric log; and an injection plan showing injection facilities and method of injection.

Determinations

1. Project file reviews revealed that important file documents are frequently not kept together in a single location, but are found in different locations throughout the District office.

2. Projects not recently reviewed are often missing critical data, possibly because the data were not originally submitted, or because they were not organized in a manner that was easily manageable or accessible. This makes it difficult to determine whether the project files have all the necessary data needed to evaluate the project. It also makes it difficult to cross-reference and/or check information for accuracy. This issue was not limited to any particular time period or operator, rather seems to be an ongoing filing and data management problem.

Recommendations

1. The District is currently making an effort to address the issue of files management with the implementation of electronic filing, with the goal of storing all project file documents in a single electronic database. The majority of recent project applications are submitted electronically, making it easier to assemble all the components of the project file into the appropriate electronic folder. For older projects, the District is completing a files scanning project wherein paper project files are electronically scanned and stored within an electronic database. This practice should be continued, and ways to enhance this practice (e.g. – better data management systems) should be evaluated.

2. For projects already approved, missing data should be requested from the operator to complete data gaps in project files.

3. Project Approval Letters

Once the proposed project has been reviewed, the District determines if the project can operate in compliance with all the applicable statues, regulations and the Primacy agreement. If so, a PAL is issued to the operator. At a minimum, this PAL should contain the requirements specified in CCR Section 1714 – Approval of Well Operations, Section 1724.6, Approval of Underground Injection and Disposal Projects, and Section 1724.10 – Filing, Notification, Operating, and Testing Requirements for Underground Injection Projects. These sections of the regulations specify the conditions for approval and requirements for operating an underground injection project. Other conditions, such as safety, operational, and environmental requirements, are typically added to the PAL.

Determinations

1. PAL records were confusing. Many projects had more than one PAL in effect at the same time. Several letters rescinded prior letters by date; others had more recent approval letters referencing older approval letters.

2. Many projects have multiple injection zones, permitted at different times throughout the life of the project, all under the same unmodified PAL. Projects originally permitted for deep zones were later permitted, under the same PAL, for shallower zones, and vice versa. Such project injection wells may not be appropriately cased or cemented for injection into the proposed injection zone(s), thereby posing a threat to USDWs.

3. Many PALs were issued without clear identification of the approved zone(s) of injection.

4. Many PALs written in the 1990s and 2000s, do not include the *type* of project, whether water flood, steam flood, water disposal, or pressure maintenance.

5. Some projects have no PAL. Project #849-18-013, approved in 1977, is one example of a project that has no PAL.

6. The PALs are often generic with many having the same assumed project formation fracture gradient of 0.8 pounds per square inch per foot (psi/ft). There is no evidence on file on when or how such a fracture gradient was determined, and why all the PALs are assigned the same fracture gradient.

Recommendations

1. In addition to the current standard conditions for new PALs, new PALs should have unique identifying conditions in addition to the project identification number, field, fault block and pool. Additionally, each PAL should have an expiration date, after which it is renewed upon comprehensive review for compliance with its operating conditions, applicable statutes, rules and regulations. Each PAL must specify the date for its APR.

2. Any change in the project, including a change in operator, injection zone etc., should require the issuance of a new PAL. Injection zone changes should require a new evaluation, and a new, and unique, PAL.

3. According to the Primacy Agreement, if an operator wishes to change or modify the work plan or conditions of a project, the operator must submit a new application to the division for evaluation. If circumstances warrant, the division will issue a new permit reflecting the changes and resulting condition.

4. Each PAL must contain a list of all the wells (injectors, producers, idle and plugged wells etc.) associated with the project.

5. Every project formation fracture gradient must be based on a SRT conducted on the project's injection zone(s). Also, the date of the test must be specified on the PAL. A PAL for multiple injection zones, must identify the fracture gradient for each zone.

B. Area of Review Evaluations

As of December 2013, there were 268 injection projects listed in District 1, of which 154 were active projects. A review of a sample of District 1 injection projects was conducted to confirm whether appropriate and complete AORs had been submitted by the operator and reviewed by the Division. The MC Unit Review Team selected 45 injection projects for evaluation. UIC project files and well files were reviewed to gather data for this evaluation. This sample group comprised various project statuses (40 active, 4 terminated, and 1 rescinded project), from fields discovered in the 1930s and 1940s. The selected projects included a variety of project approval dates and project types, including water flood (WF), water disposal (WD), and gas storage (GS).

Of the 45 projects used as a sample population for this review of AOR use, 24 projects were permitted pre-Primacy (pre-March 1983), and 21 projects were permitted post-Primacy. Of the 24 pre-Primacy projects, 20 projects were permitted before, and four after, the 1978 regulations (CCR Title 14, section 1724, February 17, 1978). Of the 21 post-Primacy projects, 16 projects were permitted before, and five after, the 2010 UIC Letter of Expectations.

Tables 2 and 3 respectively, present the pre- and post-Primacy injection project findings summaries for the sample group reviewed. Tabulated data includes: project status, initial project approval date, whether an AOR was completed, number of "bad" wells identified, and comments regarding how identified potential zonal conduits were addressed.

An overview of the criteria required for evaluation of the appropriateness and completeness of an AOR is presented within **Appendix B** of this report. As detailed in the appendix, the presence, or lack of supporting AOR-essential criteria within a project or well file was used to determine whether the required project review *could have been* completed. For example, it is highly unlikely that an AOR could have been completed without casing diagrams. Casing diagrams submitted with injection project applications are critical in determining zonal isolation within the AOR. Casing diagrams are therefore a crucial application component that, when missing, suggests that an AOR could not have been conducted.

When an AOR is delineated, the casing diagrams of the wells (including open-hole wellbores) within the AOR are closely evaluated as potential conduits for fluid migration outside the intended zone of injection. For the purposes of this review, wells evaluated are classified as "good," "bad," or "gray." Wells are classified as "good" when they meet current standards of zonal isolation. Those wells identified as direct or partial conduits due to poor, inadequate or lack of cement, or mechanical problems, are classified as "bad" wells subject to remediation prior to commencement of any injection. A third category of wells referred to as "gray" wells do not fit into either of the first two categories. Gray wells were either completed and/or abandoned to the standard existing at the time of their drilling, but are not now cemented to the current standard as required by CCR section 1722.4 (Cementing casing), or do not meet the specific plugging and abandonment or annular cement lengths required by CCR, Chapter 4, Article 3, Sections 1723.1 (a) (Plugging of Oil or Gas Zones) and 1723.2 (Plugging for Freshwater Protection), Section 1723.1(b); 1723.1 (c) (4) (open hole plugging and abandonment).

Determinations

Tables 2 and **3** present findings summaries of the 45 projects evaluated. **Figures 1** through **4**, present illustrated analyses of the AOR evaluation findings discussed below.

<u>District 1 - Pre-Primacy Projects Review</u>

Only 1 of the 24 approved pre-Primacy injection project files evaluated contained sufficient AOR-essential criteria to support a complete AOR. Although these projects were approved (including the 2 terminated and 1 rescinded projects-see **Table 2**) pre-Primacy, all of the projects remained active post-Primacy and in conformance with Primacy requirements, should have been reviewed, updated, and issued a modified PAL.

Figure 1 on the following page provides an illustration of the number and percentages of AORs, completed (blue) and not completed (red) for projects sampled from the pre-Primacy and post-Primacy time periods.

Common deficiencies in pre-Primacy AOR project file evaluations include: missing well lists, missing well casing diagrams, casing diagrams with insufficient data such as the location of the top of the injection zone(s) (TIZ), cement information, specific USDW depths, or reference to a USDW, and well histories with inconsistent information.

Appropriate AOR'S Completed Pre- and Post-Primacy

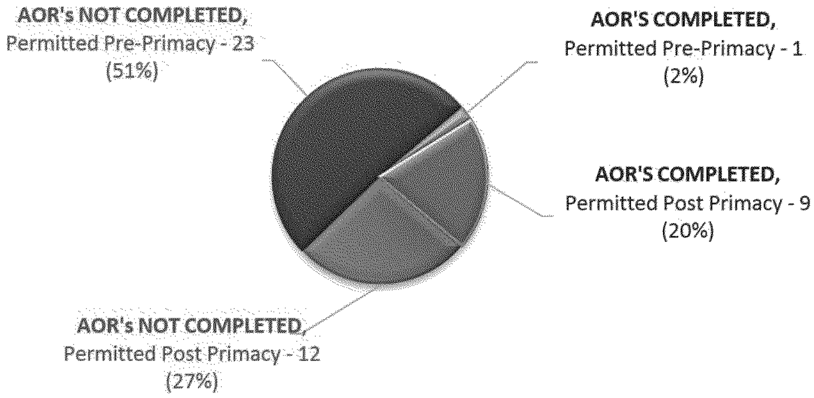


Figure 1: Appropriate AOR's completed Pre- and Post-Primacy (total 45 selected projects). AOR's not completed (78%) are shaded red and AOR's completed (22%) are shaded blue. All but one of the completed AORs was completed during the post-Primacy period.

<u>District 1 – Post-Primacy Projects Review</u>

A representative sample of 21 approved post-Primacy projects were reviewed for the presence of appropriately delineated and complete AOR evaluations, and to determine if potential conduits for injection fluid were present. Nine of the 21 projects were appropriately delineated and had complete AOR evaluations; 12 projects did not. A total of 154 bad wells were identified by District 1 post-Primacy AOR evaluations. These results are presented in **Table 3**, which gives a project code number (PC no.) for each project evaluated.

Highlights of the **Table 3** results were as follows:

1. Two approved injection project reviews indicated that no bad wells were identified by District AOR evaluations. (PC nos. 78206011 and 84903013.)

2. Two AOR evaluations identified a significant number of bad wells still under additional review by the Division as of December 2014. (PC nos. 32400015 and 32400016.)

3. Two AOR evaluations identified bad wells that were remediated as a condition of a letter or PAL. (PC nos. 84939009 and 32018003.)

4. Three AOR evaluations identified bad wells to be addressed by implementing a monitoring program. (PC nos. 66600007, 84918008 and 47806002.)

5. Graphical data for two of the projects with monitoring programs was not submitted to the

Division in accordance with a stated condition of the PAL. (PC nos. 66600007 and 47806002.)

6. Applicant operator submitted incomplete AOR data to the Division. In one instance, out of 57 wells in the one-quarter mile AOR, only 7 casing diagrams were submitted for review. A review of the casing diagrams shows inadequate casing information; moreover, there was no information on the diagrams locating the top of injection zone. (PC no. 66600008.)

7. For the 12 post-Primacy projects identified in this review as havingincomplete AOR evaluations, the data suggest thatthe District did not identify or address them. For each of these 12 projects, AORs should have been completed during the initial project application evaluation before the issuance of a PAL especiallyconsidering these projects were permitted under the post-Primacy agreement. Annually thereafter, these projects could have been brought up to standard during the APRbut were not.

8. Nine of the 21 project applications approved post-Primacy had appropriate AOR evaluations completed. Eight of the nine applications were approved between 2005 - 2013. This demonstrates an improvement in AOR completions for new applications.

9. Many project files failed to contain maps of the directional path of the wells within the AOR completely, or at all Prior to 2010, AORs did not include the directional path of wells in the area surrounding the proposed injection wells to determine the AOR boundary. Consequently, a complete or accurate list of wells within the AOR was not available.

10. Records were frequently insufficient to determine if problem wells found in the AOR evaluation were remediated prior to commencing injection.

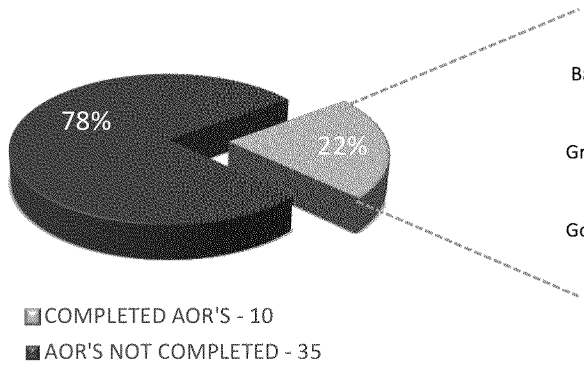
Other Determinations Concerning Post-Primacy Projects:

11. Following direction from upper Division management in 2012, District 1 no longer required use of the term “remediation” in permit language regarding “bad” wells (potential injection fluid conduits) identified during AOR evaluations. The approved PAL terminology was changed from “remediate” to “address.” It is unclear whether this terminology change was intended to meanremediation, or merely monitoring. From 2009 to 2012 there was an increase in the number of applications for new or extension of existing injection projects. This surge of applications, together with the number of incomplete applications in the queue awaiting required data, resulted in delays of project approvals. In 2012, to expedite the injection project evaluation and approval process, a new Division policy was established that allowed operators to add injection wells (new wells or well conversions) within existing injection project boundaries, without comprehensive AOR reviews. This “deferral” policy was initiated based on the premise that AOR evaluations would be performed later, during the APR process, and that the subject fields had previously been through the AOR evaluation process.

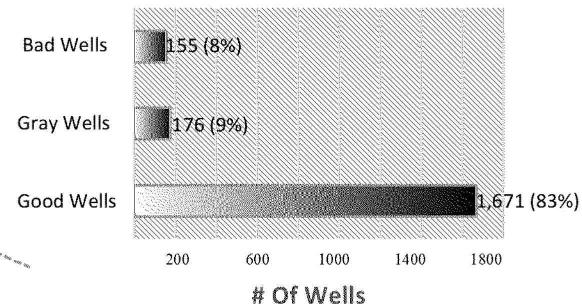
12. A review of 159 projects for APR compliance found that 5 projects had APR within the last 5 years, 135 had no evidence of an APR conducted within the last 5 years (some as long as 20 years), and 19 had no APR conducted. Evidence suggests reliance on a questionnaire submitted by operators was used as an APR. For a more in-depth analysis, refer to **Table 10**, in the annual project review section of this report.

Figures 2 and 3 below illustrate the results of the reviewed injection project evaluations and breakdown of well status percentages within the 10 completed injection projects identified both pre-Primacy (1 project) and post-Primacy (9 projects).

Overview of Pre-Primacy and Post-Primacy Injection Projects Evaluated for AOR Completion



Breakdown of Wells Reviewed



Note: A total of 2,002 wells from 10 AORswere evaluated

Figure 2: Overview of Pre-Primacy and Post-Primacy Injection Projects Evaluated for AOR Completion. An AOR evaluation should have been completed for each of the 45 selected projects.

Figure 3: Breakdown of Wells Reviewed (from the 10 completed AORs) showing the numbers and sample population percentages of the good, gray, and bad wells identified from the District 1 review of the 10 completed AORs.

Seven In-Depth AOR Evaluations Conducted During This Review:

Based on the finding that 35 out of the 45 pre- and post-Primacy projects reviewed had no AOR evaluations, the MC Unit selected a subset of 7 project files from this group to perform its own in-depth AOR evaluations. The MC Unit Review Team identified and listed the wells in each AOR, reviewing individual well histories and evaluating casing diagrams.

Determinations

These focused evaluations led to the following determinations:

1. A total of 230 well casing diagrams from the 7 injection projects were reviewed for zonal isolation. The review indicated that 37 wells (16%) were "bad", 69 wells

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(30%) were "good," 16 wells (7%) were "gray," and 108 wells (47%) were "NEI" (Not Enough Information) (see **Figure 4** below).

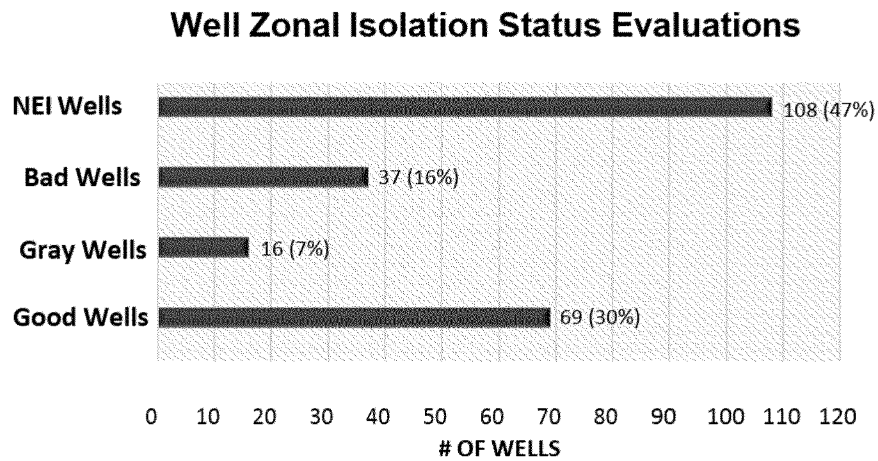

Figure 4: Well Zonal Isolation Status Evaluations (of 7 Projects Reviewed)
"Good" wells, meet the required zonal confinement; "gray" wells were either completed and/or abandoned to the standard applicable at the time of their dr illing, but not to the current standard; or do not meet the specific plugging and abandonment or annular cement lengths required by current regulations; "bad" wells evidence a direct or partial conduit from the injection zone. A total of 37 wells were identified via the detailed review as potential conduits. A large number of well files reviewed did not have enough information to make a determination whether the well has a direct, or partial conduit from the injection zone.

2. 108 well casing diagrams, or 47 percent of the 230 well casing diagrams, reviewed for this focused evaluation, lacked sufficient information. These casing diagrams did not set forth enough information to determine whether the well had complete integrity or could be a potential conduit for fluid to migrate from the injection zone. Information missing typically included casing sizes and setting depths, detailed cement information, (type, additives, amount in cubic feet, and yield if available, placement depths, perforations), depths to TIZ, to USDW, to the base of fresh water (BFW), and to geologic markers true vertical depth (TVD). Also missing, in typical samples, was an indication of whether the well is directional or vertical (straight hole), sidetracked or redrilled, and the depth to theoretical or calculated tops of annular cement, and cement plugs. Finally, these casing diagrams had not been brought up to date, and thus did not reflect the current status of the well.

3. The "bad" wells identified by the MC Unit had direct conduits or partial conduits from the injection zone. Of the 37 identified "bad" wells, 16 are currently plugged and abandoned (P&A); 17 are active, two are idle, and two are designated "unknown status" in the CalWIMS database.

4. Under certain conditions, an operating production well can become a conduit for fluid migration outside the intended injection zone if its operational status changes, or there is a change in the production well, or a change in the depth of fluid injection within the AOR of the production well. Many currently active producing wells located within the area of influence of an injection project are not cemented across the top of the injection zone. Consequently, if the well stops producing (becomes idle/shut-in), the absence of draw-down from pumping activity, which previously created a cone of fluid depression below the top of the injection zone, can allow the well to become a vertical conduit for injection fluid as production pumping subsides.

   A second potential scenario wherein a previously adequate production well can become an injection fluid conduit occurs when the operator begins injection to a shallower zone within the radius of influence of the producing well. If the production well is not cemented across the top of this previously unanticipated injection zone, the production well can become a conduit for injection fluid outside the intended injection zone.

   Despite these scenarios, there was no evidence that any of the 37 wells identified as "bad" in the project files were addressed as potential conduits.

   Eight of the 37 bad wells also failed to meet the cement standard at the base of freshwater (BFW) (3,000 parts per million TDS), which requires that, unless the BFW is located behind the surface casing which is cemented to surface, a 100 foot barrier of cement should be placed in the annular space between the casing and the wellbore across the BFW (Title 14 CCR section 1722.4). For plugged and abandoned wells a 100 foot cement plug shall be placed inside the casing across the BFW interface (Title 14 CCR section 1723.2).

Recommendations

1. The District should base all project evaluations on the requirements of Title 14 of the CCR; and applicable requirements of Title 40 of the Code of Federal Regulations (CFR) parts 144 through 146 which, as amended in July 1, 1983, set the minimum requirements for individual UIC projects.

2. All active projects should have an appropriate and complete AOR conducted for each project. If an AOR was not completed or if a project file is missing any geologic or engineering data (i.e., maps, logs, casing diagrams, etc.) required for a completed project, then this data should be submitted by the operator, reviewed by the District, and the project file updated during the APR. The District should also ensure that each project file contains a list of all the wells in the project and that the casing diagrams have complete casing, cement, and formation information, in addition to data on TDS in

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formation water.

3. When a project application is submitted, either for expansion of a project, addition of one or more wells, or conversion of a producer/observation well to an injection well, the districts should use the opportunity to verify whether a proper AOR evaluation has been conducted for that project. If no AOR evaluation has been conducted, a full AOR should be conducted prior to project approval.

4. The AOR delineation should be based on the zone of endangering influence (ZEI) vs. use of the quarter-mile fixed radius review. Unless a field study has been conducted to justify exclusive use of a fixed-quarter mile radius AOR, in a given field, analytical methods should be used in conjunction with the fixed-radius method, especially when adequate reservoir data is available. The Division must determine which method is most appropriate for each geographic area by either using the ZEI calculated value or the standard quarter-mile fixed radius. The ZEI is defined as the lateral distance surrounding the injection well in which the pressure in the injection zone is sufficient to cause the migration of fluids out of the zone. To determine the ZEI, b oth the Primacy application and 40 CFR 146.6 (b) require that a radial flow equation, such as the Modified Theis or Bernard's equation, be used when appropriate data are available. Radial flow equations predict the behavior or movement of fluid in a confined porous media, such a subsurface formation.

5. Unless a field study has been conducted to justify exclusive use of a fixed-quarter mile radius AOR in a given field, analytical methods should be used in conjunction with the fixed-radius method, especially when adequate reservoir data is available.

6. The definition of zonal isolation should be more carefully defined based on the operations proposed. When mud inside the casing is used to support an argument for zonal isolation, the adequacy of the mud as an effective barrier to fluid migration should be demonstrated.

7. Production wells considered "good" for AOR purposes, based on the assumption that continued operation should prevent their becoming a fluid conduit, should be flagged during AOR evaluation as a potential concern, and listed on the PAL. The operator should be required to notify the Division if the well is shut-in for more than 30 days as a condition of the PAL.

8. In most cases, a change in injection depth should trigger a requirement for a new AOR evaluation to determine whether wells within the AOR are adequately cemented across the new TIZ, and the remediation of wells that are not adequately cemented across the top of the new zone. The practice of changing injection zones within a well could present problems with zonal isolation resulting in potential conduits for fluid migration

since these wells were not originally constructed to isolate the new zones. Special attention should be paid to projects when the injection zones proposed are shallower than the original production/injection zones.

9. The District should confirm whether wells placed in a monitoring program are being monitored according to PAL testing requirements.

10. AOR reviewers should document all the steps taken to complete a review. All calculations and methods the engineer uses to conclude whether potential conduits exist should be documented on each casing diagram, and in the well and project files.

11. Locating the USDW in each project area should be a priority since the Primacy Agreement specifies that the USDW and base of fresh water shall be protected.

12. The District should continue the current practice of aquifer protection based on both the state BFW and the U.S. EPA USDW definitions, and zonal isolation. Also, the District should, at a minimum, spot-check the depth of BFW and/or USDW during AOR evaluations using current electric log and reservoir information.

13. The District should ensure that the depths of BFW and USDW, TIZ(s) and formation markers are identified on all the casing diagrams.

14. Casing diagrams for all well bores within an AOR should be reviewed to ensure fluid confinement to the intended injection zone.

15. The Division should acquire software for 3-D plotting of the subsurface bottom location of all wells within an AOR. The Division currently depends on the operator to submit directional survey data to prove whether or not a well penetrates the AOR anywhere along the length of the well path. Also, 3-D software should be utilized to keep track of project wells and injection formation tops

16. Records should be tracked and made easily available to expedite AOR evaluations. Project records should be placed in one location for project review. Currently, in order to review a project, an engineer needs to review multiple paper and electronic files to find all the data for a project review. District 1 is currently scanning all project and well files, with new data submitted and filed electronically. This practice should be continued and expanded upon. This will mitigate some of the file organization issues, and reduce the time needed for AOR evaluation.

17. The District should use well histories to verify the accuracy of casing diagrams in the project files (e.g. cement volumes used, cement injection point depths and intervals, casing and hole size) to provide quality assurance for the UIC project well data..

18. All injection wells given "deferrals" of AOR evaluations should have a project review completed as soon as possible. At a minimum, these wells should be evaluated to determine whether proper project evaluations were in fact previously conducted for those projects.

Additional Considerations:

19. The "gray" category of wells (see Figure 4, above) has no defined criteria, resulting in inconsistencies in well classification among staff. Also, lack of defined criteria for classifying a well as gray makes it difficult for staff to decide on the appropriate form of remediation to require.

20. Among the minimum requirements of 40 CFR Parts 144 through 146 as amended in July 1, 1983, is the delineation of the AOR based on 1) Theis equation or an equivalent analytical method; or 2) a fixed-radius of not less than one-quarter mile. Each method is supposed to be chosen based on its ability to predict with confidence the ZEI and therefore the area that is to be examined for potential pathways. The District uses the fixed-radius method in exclusion of any analytical method in determining the ZEI or AOR boundary. With reliable field data and a good understanding of the basic underlying assumptions, an analytical method should be used to delineate the boundary of an AOR based on the ZEI or to confirm the use of the fixed-quarter mile radius.

21. In the majority of evaluations, the location and depth of BFW or USDW were determined from old drilling records, spontaneous potential logs (used to detect permeable beds and formation water salinity) and resistivity logs. Our spot-checks of formation depths against electric logs found that some depths were inconsistent. With improvement in technology and the interpretative methods for determining both BFW and USDW, a more accurate result and/or confirmation of the existing data could be made.

C. Maximum Allowable Surface Injection Pressure Calculations

General

The MC Unit evaluated a representative sample of Division 1 UIC monitoring program projects to determine whether the MASPs are determined correctly and monitored to ensure compliance with project approval requirements. MASPs were reviewed for their adherence to State and Federal regulations (2010 Letter of Expectations, and 1999 U.S. EPA SRT Procedures) by analyzing SRT results --the approved test method for determining MASP—provided in UIC project folders and on the District's shared SRT data drive. The unit also queried the CalWIMS database to review the District's monitoring of active UIC well MASPs.

Of the initial 46 historical UIC project files reviewed, only four contained SRT data. This sample size was determined to be too small to evaluate whether: 1) SRT data was consistently used in establishing formation fracture gradients, and 2) SRT were conducted accurately. Determining the formation fracture gradient, i.e., the factor, in psi/ft, used to determine the pressure the formation will fracture, is necessary to set to the limit for the maximum injection pressure allowed for the project. Therefore an additional 29 SRTs, from the District's step rate test analysis conducted post-Primacy and post-Letter of Expectations, were added to the 4 historical step rate test found in the project files for a total 33 SRT. These were evaluated under the District's current SRT procedures and U.S. EPA standards.

The formation fracture gradients obtained from the SRTs were compared against the permitted injection gradients to examine the accuracy of the District's fracture/injection gradient permitting process. According to the Letter of Expectations, the permitted injection pressure should be 95% (or less) of the fracture gradient (Letter of Expectations, 2010). The review also looked at the number of SRTs witnessed in the field by District staff.

Determinations

1. None of the SRT data in the four "historical" UIC project files met the U.S. EPA standards for an acceptable SRT, and only 16 of the 33 SRTs evaluated met U.S. EPA standards. Additionally, 5 of the wells evaluated were permitted at an injection gradient above the fracture gradient, as determined by a SRT. **Table 4** provides a summary of these results.

   The most common reasons observed for the failure of SRTs relative to the U.S. EPA standards are: insufficient step-rate duration and lack of notation of the instantaneous shut-in pressure (ISIP).

2. The permitted injection pressures for each UIC injection well corresponded closely with the fracture gradients determined by the SRTs.

3. As shown on **Table 5** of this report, of the 33 SRTs evaluated, 13 were witnessed by Division staff and five were waived, leaving 15 SRTs with no indication of whether test notification or witness by the Division was provided.

4. Data management for SRTs was deficient. File reviews showed that while more recent data was entered into the Division's CalWIMS database, it was often sporadic and incomplete. Historical data, only available in hard copy, was usually not clearly marked or identified in well files, or UIC project files. This lack of clear data management procedures or systematic storage of STR reports, makes it difficult to locate test results thereby impairingdecision making. MASP are established from

fracture gradients calculated from SRT.

5. There are two permitted injection gradients. One is set for the UIC Project as a whole, and is the more general, conservative, gradient found on the PAL. The second injection gradient is set specifically for each component injection well, based on SRT result obtained for each well. The more specific injection gradient, and not the general PAL injection gradient, should therefore be used for the well-specific permit for each component well. District 1 follows this correct practice.

6. Many historical MASPs approved on original PALs have not been verified by field tests. The District has been reviewing many MASPs, and is developing a more robust testing procedure to accurately determine the MASP as per State laws and regulations.

Recommendations

1. SRT data should be included in both the UIC project file as well as the specific well file for which the SRT was conducted. It is important to document how the initial MASP and fracture gradients were determined for a UIC project, and it is also important that each injection well be assigned its own fracture gradient (as determined by a SRT), and calculated MASP. No formation is completely homogeneous, and fracture gradients can vary greatly within a single project area.

2. To properly determine fracture gradients and MASPs, a proper SRT is needed.

3. Where a permit specifies an injection gradient greater than the fracture gradient determined by an SRT, corrections to the permit should be made promptly with notification and acknowledgement by the operator.

4. The Division's CalWIMS database should be modified to include data fields for SRTs witnessed, test results, and observations, making it easier for Division staff to permit and monitor injection wells.

D. Mechanical Integrity Testing

General

Zonal isolation is required to meet the dictates of the federal SDWA. To help ensure zonal isolation, the Division requires MITs to verify injection well casing integrity, and to ensure that there is no fluid migration out of the approved zones of injection. Pursuant to title 40 of the CFR, section 46.8(a), an injection well has mechanical integrity if: (1) there is no significant leak in the casing, tubing, or packer; and (2) there is no significant fluid movement into an USDW through vertical channels adjacent to the injection well bore. This two-part criteria is verified through the **SAPTs** for internal mechanical integrity, and **RAs** to detect fluid movement.

MIT Numerical Performance Adequacy

To determine if a sufficient number of MITs were conducted in conformance with applicable testing schedules, a review of recent MITs was performed for all of the UIC wells in District 1. Due to the large number of UIC wells, the detailed review of the MIT schedule was only conducted for District 1 WD wells. All active WD wells in District 1 were reviewed, with 20 selected for further numerical MIT evaluation. MIT data for these 20 wells were compiled from the year 2000 forward.

The MC Unit reviewers noted the number of MITs conducted for each well, then compared this number to the number of tests required by the schedule. **Table 6** presents a data evaluation summary showing SAPT surveys performed versus SAPTs required. **Table 7** presents a similar data evaluation summary showing RA surveys performed versus RA surveys required.

Test Schedule

State and federal regulations require specific testing schedules for MITs. SAPTs for wells are required prior to initial injection and every five years after, while RA surveys for fluid migration are scheduled on the basis of well type, as follows:

1. Water Disposal Wells: Once every year
2. Waterflood Wells: Once every two years
3. Steamflood Wells: Once every five years
4. Cyclic Steam Wells: Once every five years (added in Letter of Expectations)

The District Deputy also has the option to modify the testing schedules on the basis of geologic and reservoir information documented and submitted by the operator.

MIT Tests Witnessed

Determining the percentage of tests witnessed by district field engineers is an important aspect of the UIC program. A U.S. EPA audit of the State UIC program set a witnessing requirement of 25% for MITs, and the district staff has made increased MIT witnessing a priority.

CalWIMS Data Entries

There are 11 possible test result selections used by District 1 in the CalWIMS database for both

RA surveys and SAPT tests. These are:

1. Cancelled
2. Deferred
3. Inconclusive
4. N/A (Non-applicable)
5. No Test
6. Not Good
7. OK/Pass
8. See Report
9. Waived
10. Waived-NEA (No Engineer Available)
11. (Blank)

Of the possible test result selections, the majority of tests generally fall under one of the following:

1. N/A – A seldom used status in the past, N/A has been redefined by District 1 staff in 2013 to be used as a means of tracking MITs that the operator did not report to District 1 staff. The ability to determine how many MITs were conducted but not reported is important when calculating the percentage of all MITs witnessed. If the test was never called in, Division staff never had the opportunity to witness the test, and these tests are subtracted from the overall number of MITs conducted when determining the percentage of MITs witnessed.

2. Not Good – MITs that fail for any reason are labeled as "Not Good". It provides a list of wells to follow up on to determine if the proper actions were taken by the operator to remediate the well. Common failures are injection above MASP, leaking packers or tubing, and holes in casing allowing injection fluid to migrate above the approved zone of injection.

3. Waived/Waived-NEA – Due to operator scheduling, and District staffing levels, there are many more MITs conducted than there are field staff available to witness. Frequently a test cannot be witnessed because the only available field engineers are witnessing other tests, or participating in other activities including higher-prioritized field work, staff meetings, or training sessions. A primary goal of District 1 is to maintain the total number of MITs witnessed to at least 25%, as per agreement with the U.S. EPA.

4. (Blank) Not an official status. "Blank" simply refers to an empty data field in the CalWIMS database. There are different reasons why some MIT status fields may be left blank, the most common being the engineer entering the data forgot to fill out one or more input boxes on the MIT form. Other causes of blank data fields are associated with older MITs for which data may not be available, or missing field data from the engineer witnessing the MIT who did not record the data properly during the test.

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Data Schedule & Witness Review Methodology

The Division considered a large number of UIC wells for the MIT test portion of this review, looking at such information as the number of wells with overdue MITs, the number of wells which currently do not pass the MIT requirements, and an estimate of the percentage of MITs witnessed in the field by Division staff. Emphasis was placed on determining if testing schedules were maintained, and if a method was in place for identifying overdue tests and bringing well testing schedules back into compliance. There may be many reasons a MIT becomes overdue, and it is critical to be able to identify and update overdue MITs.

Figures 5 & 6 illustrate the relative proportion of MIT-related data entries including operator notifications, witnessed and waived tests, and results of witnessed test results for District 1 WD wells' SAPT and RA surveys, respectively. **Tables 8 and 9** provide summaries of the percentages of MITs witnessed prior to 2013, and in 2013, respectively.

To evaluate these data in CalWIMS, specific data fields including "Last Test Date," "Next Test Due Date," "Test Interval," and the most recently entered test were reviewed. The "Last Test Date" data field was compared with the most recently entered test, and to check if a test was currently up to date, the most recently entered test date was compared to the current date of the query (11/13/13) to see if the test interval had been exceeded.

The accuracy of this "Last Test Date" data field is important because this is the method by which CalWIMS tracks overdue MITs. If the "Last Test Date" field is blank, or overdue, it appears in the report as an overdue MIT test. However, wells that are actually current on all MITs, but did not have the "Last Test Date" entered or updated, will also appear on this overdue list. It then becomes critical that the "Last Test Date" data be as up-to-date and accurate as possible to capture all overdue MITs and is something the district offices should be updating routinely when evaluating their overdue MITs.

Figures 7 through 11 illustrate the breakdown of the "Last Test Date" data. These data were determined to be correct about 50% of the time.

Findings

1. Since 2013, the District has made significant strides in improving the quality of data entries into the CalWIMS database and in eliminating the backlog of MIT data.

2. RA surveys were conducted on all of the 20-well sample groups used in this review (**Table 7**), however SAPTs were conducted on only 12 wells during this same time

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interval (**Table 6**).

3. The majority of MITs were recorded in the CalWIMS database, and the data were mostly accurate. Wells not passing their SAPT or RA survey were flagged and a notice containing the reason for the test failure was sent to the operator directing them to remediate and retest the well to obtain a passing MIT.

4. CalWIMS offers an MIT module to track overdue MITs, however it is cumbersome to use and relies on the "Last RA Date" and "Last SAPT Date" data fields. These fields are separate data boxes which an engineer must fill out when entering MIT data into CalWIMS , and are often forgotten, not updated, or left blank, especially when older data is transferred manually, separate from the MIT test data entry section in CalWIMS.

5. Four out of the 12 SAPTs were not conducted according to schedule. Only 5 RA surveys were conducted on schedule, and 7 wells had 3 or fewer missing RA surveys.

6. Field engineers do not consistently enter data in the same way, or even in the same database field, sometimes leaving database entries empty(blank data fields). This suggests that field engineers may not receive sufficient, or specific and consistent, instructional emphasis on details of field testing data collection and data entry.

7. The District has improved its performance in witnessing MITs in the field. The number of witnessed tests rose from 20% (prior to 2013) to 30% by 2013. This is more than the EPA requirement of 25%. Review of test schedule data shows that approximately 32% of RA survey and SAPTs were overdue at the time of the review team's program evaluation in 2013.

8. The Division's recent stress on the subjects of witnessing and data tracking has likely prompted more complete and accurate information entries into CalWIMS. **Tables 8** and **9** provide summaries of the percentages of MITs witnessed prior to 2013, and in 2013, respectively.

SAPT Witness Response and Outcome

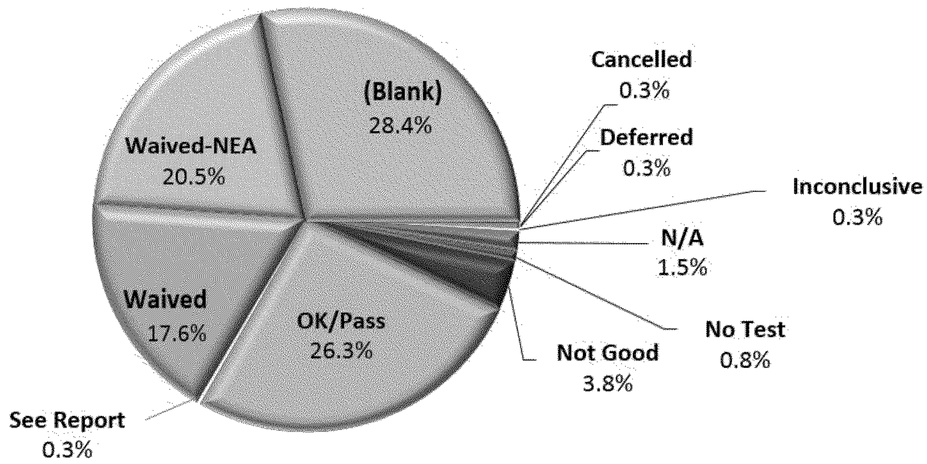

Figure 5: SAPT Witness Response and Outcome (1144 total District 1 SAPTs reviewed)

RA Survey Witness Response and Outcome

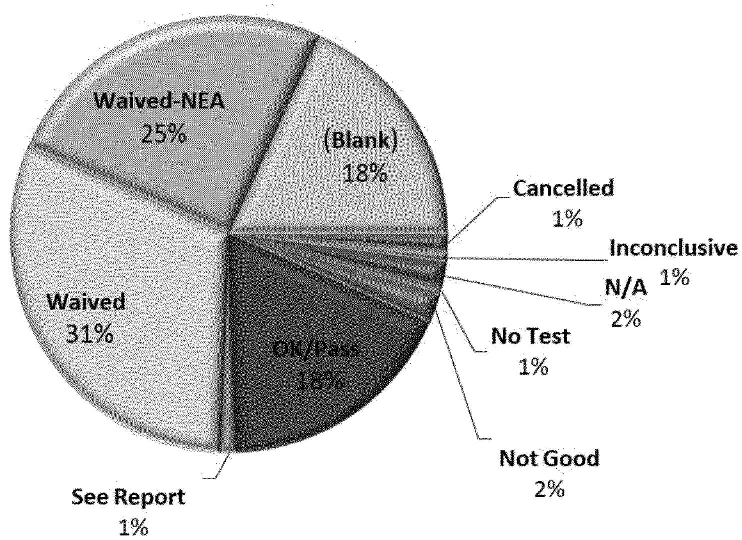

Figure 6: RA Survey Witness Response and Outcome (1,857 total District 1 RA surveys reviewed)

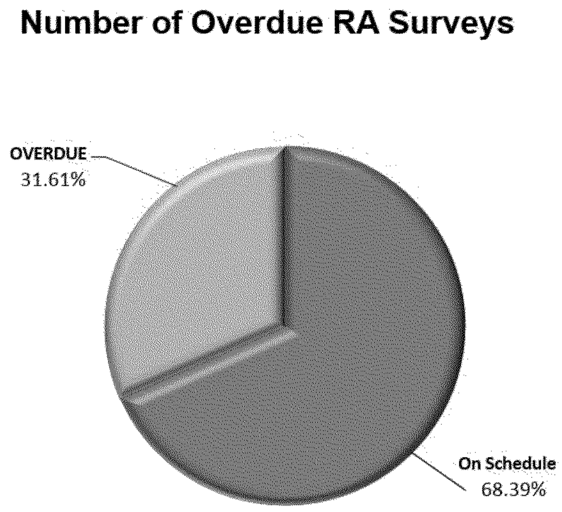

Figure 7: Number of Overdue RA Surveys

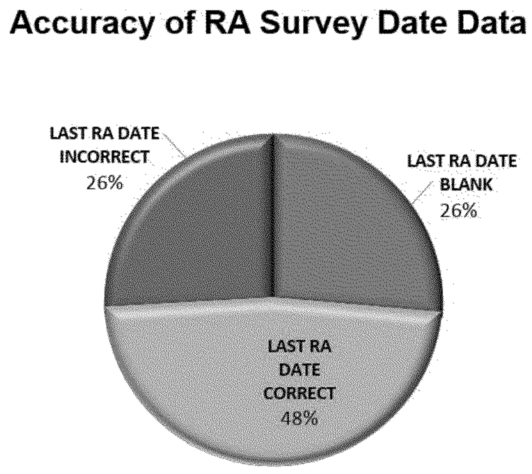

Figure 8: Accuracy of RA Survey Date Data

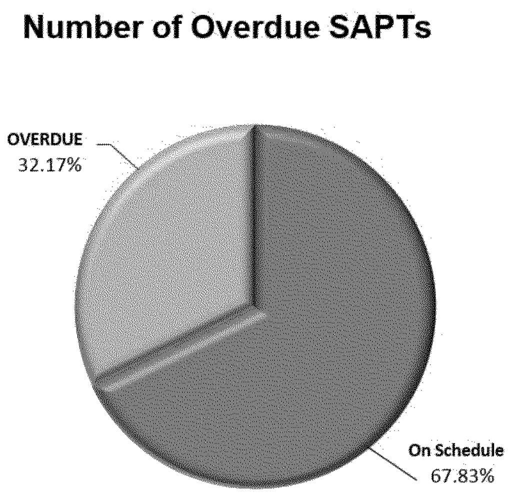

Figure 9: Number of Overdue SAPTs

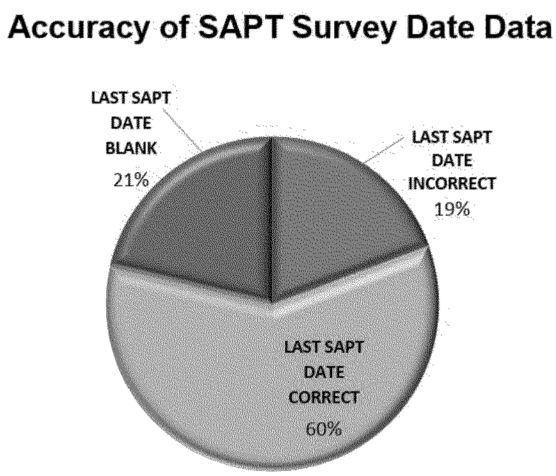

Figure 10: Accuracy of SAPT Survey Date Data

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RA Survey Test Time Interval in Months

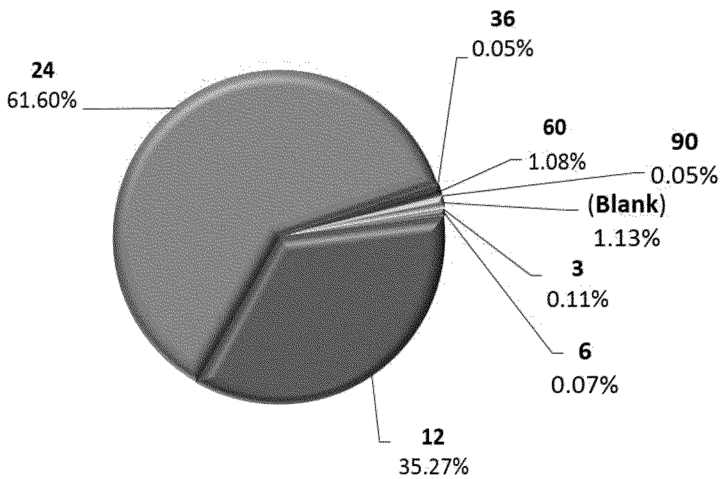

Figure 11: RA Survey Test Time Interval in Months

Recommendations

1. For a failed MIT on any injection well, the operator should be required to shut in the well, remediate the problem, and retest the well, repeating until it passes, or to plug and abandon the well and disconnect all injection lines to the well.

2. Field engineers should receive adequate instruction and emphasis on methods and importance of test data collection.

3. The District needs to catch up with the out of date MIT surveys and bring those wells back into compliance.

4. A better, automated method of populating the SAPT and RA survey date fields would eliminate the data errors and provide more accurate information which can be utilized to easily find wells with out of date MITs.

5. The District should continue improving the witness percentage of all SAPT, RA survey tests in order to keep up with the U.S. EPA requirements and provide accurate data in CalWIMS.

E. Annual Project Reviews

To verify that a UIC project is in compliance with applicable statutes, regulations and the Primacy Agreement, an annual review of the project is required. Annual project reviews (APR) are also required to determine if the PAL conditions are sufficient to ensure that the project does not pose a danger to an USDW and BFW. The MC Unit conducted an evaluation of 70 UIC projects, sampled from projects approved between 1959 through 2013 (pre-regulatory through the Letter of Expectation periods), to determine if projects were reviewed annually. In addition to the project files, other District records, such as the active project database, were reviewed to determine the frequency and the extent of the APRs.

Under the file review component, the District staff reviews the project file to ensure that: (1) all appropriate data and test results are on file; (2) they are properly analyzed; and (3) any missing data and/or information is identified. Information for annual reviews is developed by sending a questionnaire to the operators requesting information about the project. This is followed by a face-to-face office meeting with the operator to discuss the project. The third and final phase is the onsite field inspection to verify that operating conditions conform to conditions of the PAL.

From the 1930s through the 1990s the District conducted regular APRs, including office meetings with operators, to discuss projects. The frequency of those meetings increased after the adoption of the 1959 Repressuring Act. The frequency and scope of the meetings began to decrease, and were replaced in the 1990s with a reliance on written questionnaires sent to the operators to be completed and returned to the District. These questionnaires were based on project review, production and injection data.

As discussed in Section B of this document, from 2009 to 2012 there was an increase in the number of applications for injection projects. With improved data and information submittals resulting from more thorough District reviews and project data requests, coupled with a shortage of staff, a surge in applications caused delays in project evaluation and approval. To expedite injection project evaluation and approval, a new policy was established in 2012 that allowed operators to expand injection projects for currently active fields without having to go through comprehensive AOR review, on the assumption that AOR review could be accomplished at the next annual project review. However, in most instances, there was no such follow-up annual review.

Table 10 presents a summary of overdue annual project reviews from the District's 154 active, and 5 proposed projects. **Figure 12** illustrates the number of annual project reviews overdue by years overdue.

Findings

1. For many injection projects, there is insufficient documentation to verify whether the APR questionnaires were reviewed after they were received by the District, or if there was a follow-up information request, or onsite field inspection. There is, however, evidence indicating that notices were sent to operators regarding overdue tests. This indicates that some level of review was conducted.

2. There is a lack of consistency in the comprehensiveness of APRs. Several versions of APR questionnaires were found, each with varied information requirements.

3. The active project list shows that 76 projects were last reviewed in 2006. Forty-five of the 76 projects have the same review date of June 4, 2006. It is not known whether the date was the actual review date or the date the review was recorded in the database.

4. The practice of AOR project deferrals involved deferring AOR evaluations for new or converted injection wells located within existing injection project boundaries, with the understanding that these new injectors would be evaluated during the projects' APR. Out of the total 209 project applications in the queue for 2013 review, 176 AORs were deferred.

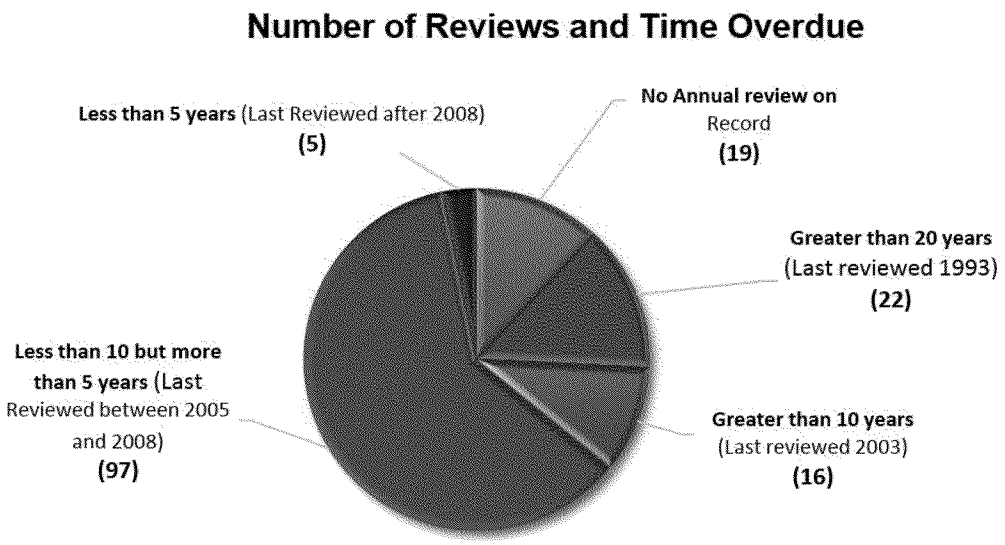

Figure 12: Number of Reviews and Time Overdue

Recommendations

1. To ensure compliance with the requirements of Title 14 of the CCR, section 1724.10(h), the District should review all active projects annually. Projects not operating in compliance should not be renewed until the operator can demonstrate

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compliance.

2. APRs should be consistent and comprehensive, and should include verification of the project's engineering analysis, review of required tests and their respective analyses, and review of special conditions of the PAL. Reviews should include field verification of PAL conditions and special requirements.

3. With anticipated increases in staffing, the District should use the APR as an opportunity to conduct comprehensive AOR evaluations of projects that have not previously had an evaluation conducted.

4. Several versions of the APR questionnaire displayed varied and inconsistent information requirements. APR questionnaires should be comprehensive and standardized for use for all operators.

5. The questionnaire used for APR should be revised to include the provisions of the Division's Well Stimulation Treatment Program (SB 4).

IV CONCLUSIONS

The Division of Oil, Gas and Geothermal Resources (Division) has conductedan in-depth review and evaluation of the Underground Injection Control (UIC) Program of the District 1 office in Cypress, California (Los Angeles Basin). The UIC program evaluation found systemic problems in the execution of the UIC program in District 1. Some of the problems relate to local issues such as the lack of organization in the handling and storage of paper files, and project approval letters (PALs) that were confusing, overly generic, or missing. At a higher level, these problems reveal some systematic problems that have existed within the Division for many years and are the focus of active remedial activities currently. These include: insufficient staffing to address increasing regulatory workload in addition to significant remedial programmatic work, poor recordkeeping on mostly paper forms and the lack of modern data tools and systems, outdated regulations that in some cases do not address the modern oil and gas extraction environment, inconsistent and undersized program leadership, insufficient breadth and depth of technical talent, insufficient coordination among fields districts and Sacramento, and lack of consistent, regular, high-quality technical training.

The Department of Conservation and the Oil and Gas Supervisor and his staff have enacted strategies and activities to address these long-term systemic problems. The Division will soon be reorganized to improve cooperation and consistency among districts and Sacramento and improve technical and programmatic leadership with attention focused on specific regulatory programs. These include UIC, Well Stimulation, Idle and Abandoned Wells and Facilities, Emerging Technologies and Regulations, Well and Data Management, Environmental Review, and Technical Training. Regular training programs are being put in place. A robust rulemaking effort is underway that will refresh the Division's regulations to address current oil field realities. With the passage of the 2015-2016 budget, the Division has begun working through the state process to bring a well data management system and modern tools to the Division. Furthermore, the Division is undertaking high-visibility recruiting efforts to bring talent to improve the Division's geographical information systems and data management capabilities, monitoring and compliance of Division activities, environmental review, and additional staff to meet the challenges of constant improvement of the UIC program and the obligations of the compliance schedule with the US EPA.

In addition, the Division, by virtue of its compliance agreement with the US EPA, has committed to a project by project review that will commence this fall and be undertaken concurrently in all districts. The Monitoring and Compliance Unit will be deployed to both assist with the review and conduct internal oversight of the review process. Via this review, each project will be reviewed, reevaluated, and any deficiencies resolved, which in some cases may require termination of the project. The schedule for this review is contained in the plan (attached) for UIC improvements submitted to the US EPA on July 15, 2015.

Appendix A

History of Injection Regulations in California

& Development of UIC Standards

The Division of Oil and Gas (later renamed the Division of Oil, Gas, and Geothermal Resources) was created in 1915 to address the needs of the State, local governments, and industry by establishing statewide uniform laws and regulations to supervise the drilling, operation, maintenance, and plugging and abandonment of onshore and offshore oil, gas, and geothermal wells. Division mandates include preventing damage to: life, health, property, and natural resources, including underground and surface waters suitable for irrigation or domestic use, and oil, gas, and geothermal deposits.

Many of the statutes and regulations in effect today began with a focus on maximizing oil and gas production and protection of correlative rights. Although the California oil and gas industry began in the 1860s, prior to 1915 there were few formal regulations for drilling and production activities in the state. By 1915 laws were passed, under the jurisdiction of the State Mining Bureau, in response to a widespread demand from oil operators to regulate the drilling of wells. Of primary concern was the loss of oil and gas production from the infiltration of subsurface waters into producing reservoirs. In June of 1915, laws requiring operators to use metal well casings were enacted in an effort to prevent water from migrating into oil or gas-bearing strata; again, not to protect ground and surface water, but to protect oil and gas zones by keeping water out.

Table 1 of this report presents the development of regulatory standards in California as occurring within 4 major periods of significant regulatory changes divided within the principal division of pre- and post-Primacy. These periods are outlined below:

1. **1930 to 1978 - Pre-Regulation:** In the early years, the level of data and information submitted as part of a project application varied in scope and quality. The data and information were sometimes based on the standard and criteria contained in an order and/or lease agreement in effect at the time. Prior to 1958, there were no specific data and/or information requirements for project applications. Application for most projects were basically discussions of the projects followed by a written request for project approval. The discussions focused on protection of oil and gas strata, and reduction of waste or conservation of oil and gas reserves.

In 1958 the California Subsidence Act was passed in response to the issue of land subsidence due to oil and gas production from Wilmington Oil Field. With the passage of this act, came the 1959 S-59-1 repressuring plan that established specifications for operations in the Wilmington Oil Field. The plan established criteria for injection project applications. Although this Plan was specific to the Wilmington Oil Field, it became the template for injection project applications and later the forerunner of injection project approvals found in current sections 1724.7 and 1724.10 of the CCR passed in 1978.

Prior to the adoption of the plan, there was no formal application or uniform operating standard. After the adoption of the Plan (S-59-1), most project proposals included basic information such as contour maps on or near the top of the producing zone; a cross-section through the proposed injection well; an analysis of the zone water salinity and proposed water to be injected; electric logs, a well list; a letter outlining the project; and depth of BFW. Information submittals served both as project application, project proposals, and analysis. However, information quality and quantity in these vintage applications varies widely, with some project applications having no casing diagrams, cement and plug information, reservoir data.

After the passage of the Well Spacing and Unitization act in 1971, some operators used digital computer simulations to determine the best well spacing and configurations for a flood pattern. This increased the sophistication of project evaluation.

In 1974, congress passed the SDWA. This act authorized the U.S. EPA to promulgate regulations for injection fluids through wells into subsurface formations either for enhanced oil recovery or to dispose of excess produced water. The purpose of this regulation was to protect USDWs. The UIC Program of the SDWA classified injection wells according to type of injection fluid. The injection of fluids generated by the exploration and production of oil and gas through wells into subsurface formations either for enhanced oil recovery or to dispose of excess produced water was classified as Class II. This led to expansion of project data and information requirements. Of projects reviewed from this period, (1930 to 1978) that had data on file, the data included was significant and of technical value. The discussions regarding the proposed injection projects were well explained and detailed, even when there was no specific regulatory requirement. The technical discussions and engineering evaluations by some operators of the period especially after the introduction of digital computer, sometimes rival that of current project evaluations in quality and completeness. Examples of projects reviewed in this pre-regulations period are located in Appendix A of this report.

2. **<u>1978 to 1982 - Regulation to Pre-Primacy</u>:** In 1978 the Division adopted CCR Division 2, Chapter 4, Subchapter 1 Sections 1724.6 (Approval of Underground Injection and Disposal Projects), 1724.7 (Project Data Requirements), 1724.8 (Data Required for Cyclic Steam Injection Project Approval), 1724.9 (Gas Storage Projects) and 1724.10 (Filing, Notification, Operating, and Testing Requirements for Underground Injection Projects. This led to uniform data and information requirements and to a subsequent improvement in quality and quantity of data and project evaluations across the board. Also, most of the proposed projects had well penetration charts, production graphs, and geochemical information, including the formation fluid TDS. The BFW was identified and provisions for protecting it were included as well as the geologic cross-sections and contour maps through the proposed injection zone(s). The application/project description included information on reservoir characteristics, proposed source and quality of injection fluid, and the proposed injection zone. Some projects include casing diagrams of all the wells on the lease associated with the project, or a list and diagrams of all the wells thought to be affected by the project based on the proposed project flood pattern or unit agreement.

3. <u>1982 to 2010 – Primacy to Letter of Expectations</u>: In 1982, the Division entered into an agreement with the U.S. EPA effectively giving the state primary responsibility to implement the requirements of the federal UIC Program for Class II wells (Primacy). This authority required some program changes that included: two-part mechanical integrity testing, a specified area of review evaluation prior to project approval, protection of USDW (10,000 mg/L TDS or less), and clarification of protection of waters with 3,000 mg/L TDS or less. Only the mechanical integrity testing requirement was codified in regulation.

The Primacy Agreement requires Division compliance with, among other requirements, the following procedures:

- the review of <u>all</u> wells in area of review prior to project approval;
- identification of wells needing remedial work and the filing of notices of intent to
- perform remedial well work to assure such wells will not serve as conduits to freshwater aquifers;
- maintain data to show performance of the project to establish that no damage is occurring;
- conduct SRTs to determine the fracture gradient of the formation before sustained injection;
- comply with a testing program to confirm that fluid is confined to the intended zone of injection;,
- the termination of an injection project if there is evidence that damage is occurring; and other requirements.

Furthermore, the Division agreed, within the first 5 years of Primacy, to review every active existing injection project, bringing all projects into compliance with the new requirements. (The review of the project files and discussion of the Division's success rate with this agreement is presented in the APR section of this report).

AOR boundaries were established as a fixed radius distance of a quarter- mile, or radial flow equation, if appropriate data was available, to determine the ZEI. With these new requirements, most proposed underground injection projects submitted included a list of wells with casing diagrams based on a defined AOR. In addition, geochemical information (including TDS in formation water), BFW, geologic cross sections, contour maps through the proposed injection zone(s), reservoir characteristics, and the source and quality of the proposed injection fluid were required.

4. <u>2010 to Present - Letter of Expectation</u>: In May of 2010, Division management developed the Letter of Expectations to: "…help ensure that UIC Program requirements are being applied in a manner consistent with the laws, regulations, primacy application, and agreements the Division is mandated to enforce." There was emphasis on ensuring that project application packages included all required data and that the submission include good quality data and accurate supporting documentation.

In 2011, the U.S. EPA conducted an audit of the Division's UIC Program to determine compliance with requirements of the Primacy Agreement and the Memorandum of Agreement. The audit found the Division lacking in the implementation of a number of requirements, including among other items: the use of appropriate AOR particularly for disposal wells, enforcement of maximum allowable surface injection pressure, and accurate determination of fracture gradient.

As a result of this audit, the Division revised the Letter of Expectations to include recommendations from the U.S. EPA audit in future UIC evaluations. It also, outlined procedures and clarified UIC Program standards for staff to apply during injection project review, permitting, monitoring, enforcement, and maintenance of project and well records. This period has seen the greatest improvement in data submission and analysis. There has also been a greater emphasis and use of the ZEI in determining the AOR (versus fixed-radius review).

APPENDIX B

UIC Program Concepts Review
Area of Review
Zonal Isolation
Base of Fresh Water
Underground Sources of Drinking Water

Area of Review

The AOR, also known as the ZEI, is defined as the area surrounding an injection well or wells in which the pressure change in the injection zone is sufficient to cause the migration of fluid out of the zone during the life of the project. The intent of the AOR is to identify the area around injection wells that will be evaluated to locate potential conduits for fluid movement out of the zone. The **process** of identifying this surrounding area is the AOR, and the **review** of the condition of the wells in this area is the AOR evaluation.

Determining the AOR accurately requires an evaluation of data that includes, but is not limited to the zone: depth and thickness, porosity and permeability, fluid characteristics, formation pressures, geologic structure, lithology, and changes to these parameters with distance from the well. Furthermore, consideration must be given to the proposed rate of injection, the dynamics in the reservoir resulting from the activity of surrounding wells, and the planned duration of injection.

The injection of fluids into a formation requires the formation to have effective qualities of porosity and permeability. Depending on the properties of the reservoir, injection fluids can move quickly or slowly through a formation potentially increasing the pressure in the reservoir. It is this mechanism that helps to drive, or push, hydrocarbons to producing wells to increase the recovery of oil and gas. This driving force, or pressure front, may affect wells within the vicinity. Fluids will flow from areas of higher pressure to lower pressure if there is a pathway through which flow can occur. This “path of least resistance” will determine the path fluids will take. If wells within the area of influence are not properly sealed, reservoir fluids and/or injection fluids can migrate out of the confining reservoir through improperly sealed wells, and into other zones and aquifers above or below the injection zone.

Possible conduits can be found in:

- Active, inactive, P&A wells located within a distance influenced by injection operations
- Formations with non-barrier faults and/or fractures
- Porous formation boundaries in natural conductivity with each other

Wells located within the area of influence of an injection well where the effects of injection can be felt are evaluated to identify wells not properly cased and cemented, and identify possible conduits for fluid migration out of the zone. These wells must be remediated. In cases where this is not possible because access to the well is blocked, injection operations are not allowed. In a few cases, if appropriate, a buffer zone is created around the injection well, and a well monitoring program is designed to detect fluid movement.

Some of the factors that are taken into consideration when determining the radius of the AOR include:

- Local and regional geology
- Local and regional stratigraphy
- Geologic structure
- Properties of the proposed injection reservoir
- Location of useable surface and ground waters
- Flow properties of the injection zone
- Determination of the vertical hydraulic gradient
- Propose operating conditions

An appropriate AOR should be determined on a case-by-case basis. Where there is data on past injection activity, the use of a "fixed-radius review" may be appropriate.

For Division purposes, as outlined in the Primacy Agreement, the Division can use the one-quarter mile area surrounding each injection well for a "fixed-radius review." This surrounding area can be larger or smaller depending on reservoir conditions and structural geology; larger if the injection zone is very permeable, or smaller if the existence of bounding faults and formation pinch outs limit fluid migration. The district office may request the operator provide data for a larger AOR. A radial flow equation, such as the Modified Theis or Bernard's, may be used to determine the lateral distance in which the pressures in the injection zone may cause migration of the injection or formation fluid out of the permitted zone. The actual distance calculated by the radial flow equation is only as accurate as the data used in the determination. The calculated AOR may or may not reflect the actual distance injected fluid may travel because formations are not homogenous nor equally extensive in all directions. Where gas migration is an issue (gas is more mobile than fluid), care is needed to determine an appropriate AOR.

Neither the analytical method, nor the fixed-radius should be used exclusive of each other because the ZEI can vary from one injector to another even within the same reservoir or field. It is therefore necessary to choose any method only if it is technically justified and based on the particular reservoir, well hydraulics, hydro-geology and other information specific to the project.

Whatever method chosen must be able to satisfy the basic requirement of the AOR; which is to be able to predict with confidence, the ZEI, so that review of migration conduits and potential for contamination can be identified and remediated prior to initiating injection.

Directionally drilled wells in the AOR must be identified. The delineation of the area must take into consideration the subsurface location of straight hole and directionally drilled wells in the project area. The accurate surface and subsurface location of every well in this area must be determined and the current condition of the casing and cement seals evaluated. Wellbore trajectories through the subsurface must be accurately plotted to determine the location where the wellbore intersects the top of the formation.

For multiple directionally drilled wells, such as exist in the Los Angeles area, the determination of the AOR can be very complex and requires the operator to provide proof that wells are or are not located within the area of influence.

In this complex environment, identifying the exact location of wellbores and the location of wells with respect to each other at every depth is difficult to determine without 3-D spatial analysis. To identify wells that fall in the AOR, the Division is dependent on industry to provide detailed maps, and supporting X, Y, Z plots detailing distances between where the wells intersect the injection zone and the one-quarter mile radius. The complexity of these AORs make a review difficult and time consuming as meticulous attention to details is required to accurately assess the absence of migration pathways and fluid conduits.

The diagram on the following page illustrates the difference between the use of a straight hole and a directional well in determining the AOR. Notice how the directional well plot in the subsurface can significantly extend the AOR.

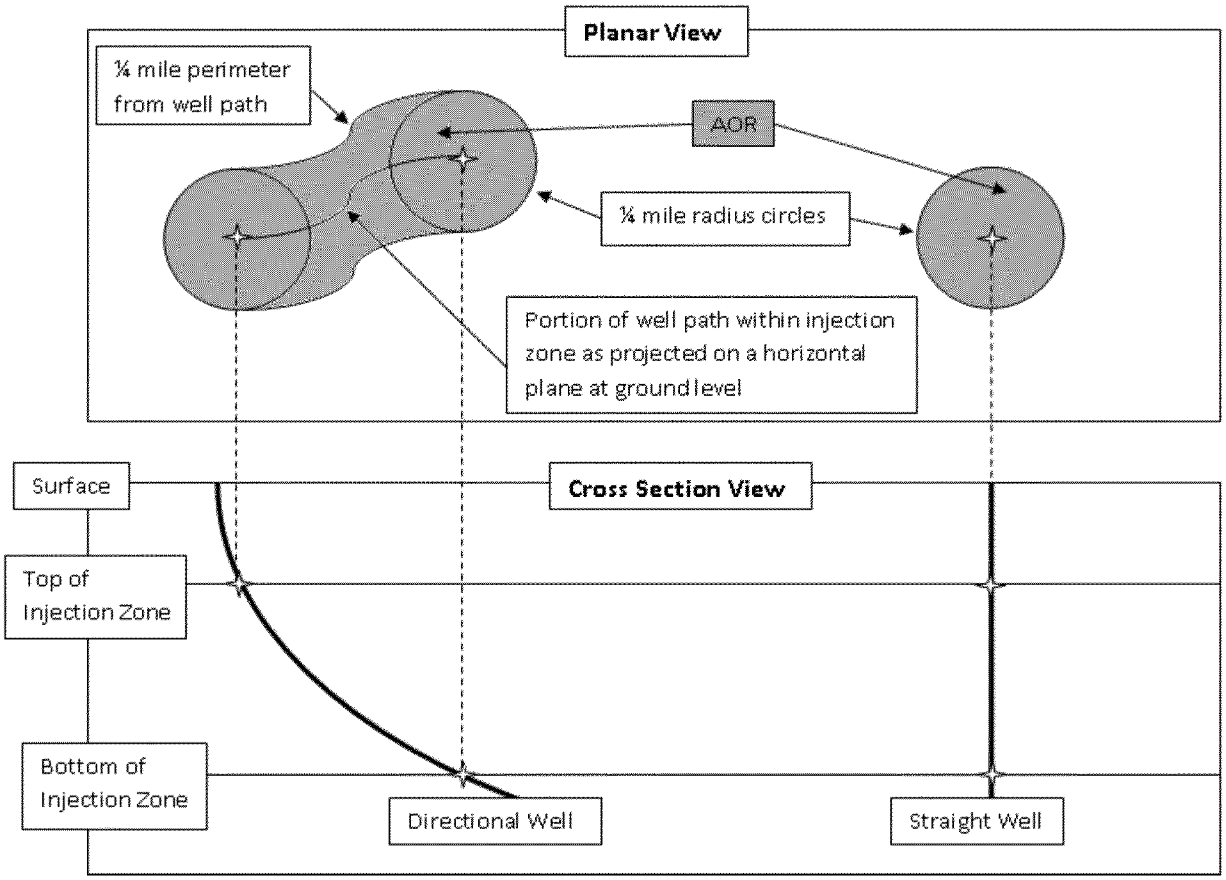

Figure A1: Area of Review outline of directionally drilled and straight hole wells.

Once the AOR has been accurately identified, casing diagrams of all wells located within this area must be analyzed and evaluated to ensure there are no pathways for fluid migration. Operators are required to submit casing diagrams that detail casing construction, including the location of annular and internal cement and casing perforations. Casing construction review is the next step in determining zonal isolation.

Criteria for Determination of Appropriate Use and Completion of the AOR:

Evaluation criteria for the appropriate use of the AOR included determination of whether an AOR had been completed in the following instances:

- During original injection project application
- After Primacy (1983) (all existing injection projects should have been brought into compliance with current standards)
- During APRs if an AOR had not been completed
- On change of injection zone within an existing project

For the AOR: Evidence that an AOR evaluation can be completed for a project has to include the following within the project file:

- a list of all wells within the AOR, including the proposed injectors and wells within the one-quarter mile area,
- casing diagrams for all wells within the AOR,
- for wells within the AOR not penetrating the proposed injection zone: Evidence that wells were not drilled through the top of the injection formation,
- for directionally drilled wells: Evidence showing the subsurface location with respect to other wells in the AOR where the well penetrates the injection zone, and the location of the well with respect to other neighboring wells,
- geologic information with the TIZ clearly marked on casing diagram for each well,
- BFW depth marked on the casing diagram,
- top and bottom location of cement plugs inside casing, and whether the cement was witnessed and/or verified by a tag, with depth noted,
- top and base of cement present in the well annulus, and information on the quantity and cement mixture used for each cement section,
- whether cement location and quality was verified with a cement bond log (CBL), and
- date the casing diagram was prepared for comparison with application submittal date to verify that it is up-to-date.

For Casing Diagrams: When an AOR is delineated, the casing diagrams of the wells within the AOR are closely evaluated as potential conduits for fluid migration. Wells are classified as "good" when they meet current standards of zonal isolation. Those wells identified as potential conduits due to poor or inadequate cementing, or mechanical problems, are classified as "bad" wells subject to remediation prior to commencement of any injection. A third category of wells referred to as "Gray" wells do not fit into either of the first two categories. Gray wells were either completed and/or abandoned to the standard existing at the time of their drilling, but are not now sealed to the current standard; or do not meet the specific plugging and abandonment or annular cement lengths required by CCR, Chapter 4, Article 3, Sections 1723.1 (a) (Plugging of Oil or Gas Zones) and 1723.2 (Plugging for Freshwater Protection), Section 1723.1 (b); 1723.1(c) (4) (open hole plugging and abandonment)

Evidence that a casing diagram review has been conducted to determine zonal isolation requires the inclusion of the following minimal critical information within the project file:

- casing sizes and setting depths for all well casing
- detailed cement information, i.e., cement type, additives, quantity in sacks of cubic feet, and yield if available, placement depths, perforations
- depth to TIZ and geologic markers
- TVD of hole
- whether the well is directional or a straight hole

- size of drilled wellbore, reamed intervals, and depth of wellbore sizes
- whether well bore is the original hole, sidetracked hole, or redrilled hole
- theoretical or calculated tops of annular cement, and
- cement plugs, depth to bottom and top, tagged depth

Zonal Isolation

The fundamental objective of injection operation oversight is to ensure the containment and confinement of the injected fluid to the formation or zone approved by the Division. This standard is reflected in Division statutory language that requires the isolation of oil and gas producing zones and protection of underground and surface waters from the infiltration of detrimental substances. Simply stated, “zonal isolation,” as it is commonly referred, requires that fluid injected into an approved zone must stay in that zone. Migration of fluids out of the approved zone is not allowed since fluid movement can threaten fresh waters and migrate into oil and gas producing zones causing the watering out of hydrocarbon zones and loss of production.

Zonal isolation can be maintained through a variety of methods. The most protective method is by creating physical barriers between the injection zone and the zones above and below. (For this report, zonal isolation is limited to the evaluation of formations above the approved zone of injection and the protection of freshwaters.)

The drilling of a well removes existing natural physical barriers between formations and the zones within a formation. It is important to note that not all formation or zone boundaries are barriers to fluid movement. Some formations composed of sands and silts by their nature are porous and permeable, to a degree, and allow for fluid movement between them. Zonal isolation is dependent on the quality of the cap rock above the injection zone and its ability to resist fluid movement into it. Such qualities as low permeability, low porosity, and lack of faults and fractures are necessary to prevent fluid movement. Shale makes a good cap rock because of its typical low permeability; i.e., the ability of fluid to move through pore spaces.

The placement of mechanical barriers in wellbores for the purpose of fluid containment, in essence an attempt to replace the natural barriers removed during drilling, can be an effective means of zonal isolation. Such methods as the placement of good quality casing and cement during well construction and maintenance activities can prevent fluid movement out of the injection zone (for further discussion, see the well plugging and abandonment section). Non-mechanical methods can also be implemented, such as control of formation or zone pressure. This method can be effective, but requires continuous monitoring to provide assurances. In some areas of California, such as highly urbanized locations, the pressure monitoring system may be the only means of ensuring zonal isolation because wells are located underneath structures where they cannot be readily accessed. Monitoring programs, however, are limited in effectiveness and where conduits exist for fluid migration, injection should not be allowed.

Base of Freshwater and Underground Sources of Drinking Water

Historically the Division has protected groundwater suitable for irrigation and domestic purposes. The demarcation of this freshwater limit became 3,000 mg/L TDS. The reference for this limit is unknown but has been used by many regulatory agencies and industry for decades. When the SDWA was passed by the federal government, a new well defined standard was implemented. This standard identifies protected aquifers as, an aquifer, or its portion, that contains a sufficient quantity of ground water to supply a public water system; and currently supplies drinking water for human consumption; or contains fewer than 10,000 mg/L TDS; and which is not an exempted aquifer. This 10,000 mg/L limit was included in the Primacy agreement between the Division and the U.S. EPA and since 1983 required protection when permitting Class II injection wells. The Division continued to protect the BFW at 3,000 mg/L TDS and was responsible for the protection of 10,000 mg/L TDS ground waters.

Federal regulations allow for the exemption of aquifers less than 10,000 mg/L TDS after a lengthy application process that requires concurrence from the state water quality agencies. However, it is important to note that aquifer exemptions are divided into two categories, i.e., major and minor exemptions. Minor exemptions are those exemptions for aquifers with fluids between 3,000 and 10,000 mg/L TDS and major aquifer exemptions are for those fluids less than 3,000 mg/L TDS. Major aquifer exemptions must be submitted to the Washington D.C. office of Drinking Water for approval and are difficult to get approval for. Aquifer exemptions requested through the Division to the federal office must have concurrence from the California State Water Quality Control Board.

Table 1: Project Applications Sample Distribution by Period and Percent Incomplete

Historical Regulatory Periods		Number of Sample Injection Projects	Number of Incomplete Project Applications	Percent Incomplete Project Applications
Year Intervals	Significant Change of Program Standard			
Pre-Primacy				
Pre-Regulation - 1978	Pre-Regulation	19	11	58%
1978 - 1982	First Regulations- to Pre-Primacy	6	3	50%
	Pre-Primacy Totals	**25**	**14**	**56%**
Post-Primacy				
1982 - 2010	Primacy to Letter of Expectations	21	10	48%
2010 - 2013	Letter of Expectations	6	1	17%
	Post-Primacy Totals	**27**	**11**	**41%**
	Grand Totals	**52**	**25**	**48%**

Notes: A brief description of each period interval is provided below. More detailed discussion of program standards development is included in Appendix A of this report.

1930 - 1978 Pre-Regulation – Statutes and regulations prior to 1978 relied primarily on requirements to prevent fluid movement from watering out (diluting) an offset operator's hydrocarbon reservoirs.

1978 - 1982 First Regulations - to Pre-Primacy – In 1978, CCR section 1724 was promulgated to require specific data be submitted with an application for injection project approval.

1982 - 2010 Primacy to Letter of Expectations– In 1982, the Division entered into an agreement with the U.S. EPA effectively giving the state prima ry responsibility to implement the requirements of the federal UIC Program for Class II wells (Primacy). This authority required some program changes that included: two-part mechanical integrity testing, a specified area of review evaluation prior to proje ct approval, protection of underground sources of drinking water (USDWwaters 10,000mg/L TDS or less), and clarification of protection of waters with 3,000 mg/L TDS or less. Only the mechanical integrity testing requirement was codified in regulation.

2010 - 2013 In 2010, in 2010 the Division prepared the policy Letter of Expectations for the clarification of portions of the UIC program implementation. During this time, Division district offices were instructed to implement the Letter of Expectations duing permitting and annual reviews of existing projects.

Table 2: AOR Reviews - Pre-Primacy

Project Code	Project Status	Initial Date of PAL	Appropriate AOR(s) Completed?		Bad Wells Identified	How Were Potential Conduits Addressed?
			Yes	No		
84915001	Active	8/13/1954	--	X	No AOR	No AOR
84918002	Active	3/14/1958	--	X	No AOR	No AOR
84915002	Active	3/17/1958	--	X	No AOR	No AOR
50406001	Terminated	7/1/1959	--	X	No AOR	No AOR
84903001	Active	10/15/1959	--	X	No AOR	No AOR
38203001	Active	1/4/1965	--	X	No AOR	No AOR
38212001	Active	1/4/1965	--	X	No AOR	No AOR
38215001	Active	5/4/1965	--	X	No AOR	No AOR
84918006	Active	1/4/1967	--	X	No AOR	No AOR
78206002	Active	1/24/1969	--	X	No AOR	No AOR
61803001	Active	4/7/1970	--	X	No AOR	No AOR
61803002	Active	4/7/1970	--	X	No AOR	No AOR
78206003	Active	5/6/1971	--	X	No AOR	No AOR
84903003	Active	12/6/1971	--	X	No AOR	No AOR
78206004	Active	12/15/1972	--	X	No AOR	No AOR
66600002	Active	1/31/1973	--	X	No AOR	No AOR
66600003	Active	1/31/1973	--	X	No AOR	No AOR
68812001	Active	2/28/1974	--	X	No AOR	No AOR
84903005	Active	4/23/1975	--	X	No AOR	No AOR
68806004	Active	8/8/1977	--	X	No AOR	No AOR
38212002	Active	1/12/1979	--	X	No AOR	No AOR
38215002	Terminated	8/30/1979	--	X	No AOR	No AOR
84906013	Active	8/19/1981	X	--	1	Remediated - under condition of PAL
78206006	Rescinded	12/15/1982	--	X	No AOR	No AOR
Totals	**24**		**1**	**23**	**1**	

Notes: Projects reviewed were from fields discovered in the 1930's and 1940's
PAL - Project Approval Letter
AOR - Area of Review

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Table 3: AOR Reviews – Post-Primacy

Project Code	Project Status	Initial Date of PAL	Appropriate AOR(s) Completed?		Bad Wells Identified	How Were Potential Conduits Addressed?
			Yes	No		
84918010	Active	10/18/1985	--	X	No AOR	No AOR
84939012	Active	10/18/1985	--	X	No AOR	No AOR
66600005	Active	4/29/1988	--	X	No AOR	No AOR
32021001	Active	5/20/1988	--	X	No AOR	No AOR
50406003	Active	11/21/1989	--	X	No AOR	No AOR
32003001	Active	7/10/1991	--	X	No AOR	No AOR
84903011	Active	2/25/1992	--	X	No AOR	No AOR
66600007	Terminated	11/10/1992	X	--	Unknown	Monitoring Program - Under condition of the PAL
7000010	Active	11/9/1995	--	X	No AOR	No AOR
66600008	Terminated	6/3/1996	--	X	Unknown	Monitoring Program - Under condition of the PAL
7000011	Active	8/11/1998	--	X	No AOR	No AOR
68806005	Active	1/7/2000	--	X	No AOR	No AOR
50403001	Active	4/25/2001	--	X	No AOR	No AOR
84918008	Active	9/13/2005	X	--	Unknown	Monitoring Program - Under condition of the PAL
32400015	Active	8/2/2007	X	--	46	AOR Under review
32400016	Active	8/2/2007	X	--	98	AOR Under review
84939009	Active	10/7/2010	X	--	2	Remediated - By District mandate
32018003	Active	11/22/2011	X	--	2	Remediated - Condition of a Permit
47806002	Proposed	4/25/2013	X	--	6	Monitoring Program - Under condition of the PAL
78206011	Proposed	4/25/2013	X	--	0	No Bad Wells Identified
84903013	Active	7/29/2013	X	--	0	No Bad Wells Identified
Totals	21		9	12	154	

Notes: PAL - Project Approval Letter
AOR - Area of Review
Projects reviewed were from fields discovered in the 1930's and 1940's

Table 4: Step-Rate Test Review Summary

Results from a Total of 33 Division 1 Step-Rate Tests Reviewed			
SRTs Meeting EPA Standards (Acceptable)	SRTs Not Meeting EPA Standards (Not Acceptable)	Permitted Injection Gradients < SRT Fracture Gradients (Acceptable)	Permitted Injection Gradients > SRT Fracture Gradients (Not Acceptable)
16	**17**	**28**	**5**

Notes: SRT - Step Rate Test
< - Less than
> - Greater than

Table 5: Division Witnessed Step-Rate Tests

Division Witnessed SRTs	
Witnessed	13
Waived	5
Unknown	15
Total	**33**

Notes: SRT – Step-Rate Test
Waived - Indicates that the operator provided advance notice of the impending SRT, and was given permission to proceed with the test without witness by the Division.
Unknown - Indicates that there is no record of the operator's advance SRT notice to the Division.

Table 6: SAPTs Performed Versus SAPTs Required

Well API Number	Date of First Test (Post 2000)	Inj. Start Date	Idle Well Time	Test Schedule, Months	SAPT Tests Required Since 2000	SAPT Tests Performed
03701055	7/22/2014	4/1/2007	11/11 - 10/12, 1/13 - 3/13, 7/13 - 3/14	60	1	1
03701813	3/21/2014	4/1/2006	1/08 - 9/10, 6/11 - Present	60	1	2
03707204	3/7/2012	1/1/1977	2/12 - 4/12, 9/13 - 11/13	60	3	2
03712459	6/21/2013	7/1/2000	4/03 - 8/04	60	2	3
03717304	3/12/2014	7/1/1977	None	60	3	2
03718805	9/5/2006	2/1/1979	None	60	3	1
05904675	7/16/2014	8/1/1994	1/00 - 8/00, 12/02 - 5/05*	60	3	1
05907666	7/22/2009	2/1/2002	5/06 - 10/07, 2/08 - 8/08	60	2	6
05920082	6/23/2008	7/1/1977	1/00 - 3/08	60	2	2
05921169	3/31/2006	6/1/2006	1/13 - Present	60	2	3
23722797	6/28/2009	7/1/2003	9/11 - Present	60	2	2
23722902	3/21/2012	8/1/2012	None	60	1	2
	Totals				25	27

Notes: SAPT - Standard Annular Pressure Test
* During this time period the injection well only injected every other month

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Table 7: RA Surveys Performed Versus RA Surveys Required

Well API Number	Date of First Test (Post 2000)	Inj. Start Date	Idle Well Time	Test Schedule, Months	RA Surveys Required Since 2000	RA Surveys Performed
03701055	5/16/2008	4/1/2007	11/11 - 10/12, 1/13 - 3/13, 7/13 - 3/14	12	6	3
03701813	2/9/2007	4/1/2006	1/08 - 9/10, 6/11 - Present	12	3	3
03707204	10/16/2001	1/1/1977	2/12 - 4/12, 9/13 - 11/13	24^	7	6
03712459	9/24/2004	7/1/2000	4/03 - 8/04	12	11	3
03717304*	5/29/2001	7/1/1977	None	24^	7	7
03717592	1/14/2004	11/1/1984	11/11 - 5/12	12	14	5
03718805	4/17/2001	2/1/1979	None	12	14	5
03718809**	4/17/2001	2/1/1979	2/00 - 8/00	12	13	6
05904675**	4/25/2001	8/1/1994	1/00 - 8/00, 12/02 - 5/05*	12	13	8
05906986	2/9/2000	9/1/1982	2/04 - Present	12	4	2
05906987	2/4/2004	7/1/1977	1/00 - 2/04	6	19	4
05907002	4/25/2001	5/1/1987	2/02 - 6/05*	12	14	7
05907619	1/20/2000	8/1/1999	11/01 - Present	12	1	1
05907666	3/13/2002	2/1/2002	5/06 - 10/07, 2/08 - 8/08	12	10	5
05920082	4/11/2008	7/1/1977	1/00 - 3/08	12	6	5
05921169	7/12/2006	6/1/2006	1/13 - Present	12	7	5
07100227	6/12/2006	5/1/1987	1/00 - 8/01, 1/03 - 6/03, 9/03 - 12/03, 2/04 - 6/04, 2/09 - Present	24^	3	1
23722797	9/23/2003	7/1/2003	9/11 - Present	6	15	18
23722902	6/8/2001	8/1/2012	None	3	5	7
23726553*	9/20/2011	8/1/2008	None	6	11	9
	Totals				183	110

Notes: RA - Radioactive Tracer
* During this time period the injection well only injected every other month
** Well with failed test(s) - not retested
^ Wells with testing schedules greater than the 12 month schedule defined in the regulations

Table 8: MITs Witnessed Prior to 2013

SAPTs Prior to 2013		RA Surveys Prior to 2013		Collective SAPT & RA Surveys conducted Prior to 2013	
Total SAPTs	**921**	**Total RAs**	**1052**	**Total MITs (SAPTs plus RAs)**	**1973**
Cancelled	3	Cancelled	5	Cancelled	8
No Notice (N/A)**	9	No Notice (N/A)**	0	No Notice (N/A)**	9
No Notice (NG, Blank)^	47	No Notice (NG, Blank)^	68	No Notice (NG, Blank)^	115
Subtotal SAPT	**862**	**Subtotal RA**	**979**	**Subtotal MIT**	**1841**
Witnessed SAPT	213	Witnessed RA	159	Witnessed MIT	372
% Witnessed*	**25%**	**% Witnessed***	**16%**	**% Witnessed***	**20%**

Notes: MIT - Mechanical Integrity Test (comprising both SAPTs and RAs Surveys)
SAPT - Standard Annular Pressure Test
RA - Radioactive Tracer Survey
N/A - no advance notice of test/survey was provided to the Division
NG - Not Good; test failed
* The witnessed MIT ratios are based on the number ofthe witnessed MITs (comprising SAPTs and RAs) over their respective subtotals, whicheliminate the tests for which no advance test notice was provided to the Division (N/A), tests/surveys thatwere cancelled by the operator (cancelled), or test/surveys for which insufficient data is available in Division records to determine whether the test was witnessed (Blank).
** These tests were labeled as "N/A" to indicate that the operator failed to notify the District office to witness the test
^ These tests were labeled as "Not Good" or left blank, however the notes written by the field engineer stated that the operator failed to notify the District office to witness the test.

Table 9: MITs Witnessed in 2013

SAPTs 2013		RA Surveys 2013		Collective SAPT & RA MITs 2013	
Total SAPTs	**223**	**Total RAs**	**805**	**Total MITs**	**1028**
Cancelled	1	Cancelled	19	Cancelled	20
No Notice (N/A)	8	No Notice (N/A)	30	No Notice (N/A)	38
No Notice (NG, Blank)	3	No Notice (NG, Blank)	14	No Notice (NG, Blank)	17
Subtotal SAPT	**211**	**Subtotal RA**	**742**	**Subtotal MIT**	**953**
Witnessed SAPT	77	Witnessed RA	207	Witnessed MIT	284
% Witnessed*	**36%**	**% Witnessed***	**28%**	**% Witnessed***	**30%**

Notes: SAPT - Standard Annular Pressure Test
RA - Radioactive Tracer
MIT - Mechanical Integrity Test (comprising both SAPTs and RAs)
N/A - no advance notice of test/survey was provided to the Division
NG - Not Good; test failed
* The witnessed MIT ratios are based on the number of the witnessed MITs (comprising SAPTs and RAs) over their respective subtotals, which eliminate the number of tests for which no advance test notice was provided to the Division (N/A), tests/surveys that were cancelled by the operator, or test/surveys for which insufficient data is available in Division records to determine whether the test was witnessed (Blank).

Table 10: Overdue Annual Project Reviews

Years Overdue*	Number of Reviews Overdue	Percentage of Overdue Reviews Over 159** Total Projects
No annual review on record	19	11.95
> 20 years (last reviewed 1993)	22	13.84
> 10 years (last reviewed 2003)	16	10.1
< 10 years > 5 years	97	61
< 5 years (last reviewed after 2008)	5	3.1

Notes: * From the end of the 2013 files review
** Including 5 proposed project

Department of Conservation,
Division of Oil, Gas, and Geothermal Resources

Interagency UIC Program Improvement Planning: Major Correspondence and Deadlines

Appendix 2 to Report to the California Legislature under SB 855 (2010)

Attachments comprising Appendix 2:

1. Division and State Water Board February 6, 2015 Letter to US EPA;
2. USEPA's March 9, 2015 Response
3. Division and State Water Board May 15, 2015 letter to U.S. EPA;
4. USEPA's May 28, 2015 response letter; and
5. Agreed Joint Submittal to US EPA, July 15, 2015]